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PROTOCOL REVISION INFORMATIONAL FILINGS BY THE ELECTRIC RELIABILTY COUNCIL OF TEXAS	§ § § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

ERCOT'S NOTICE OF NODAL PROTOCOL REVISIONS (APRIL 1, 2023)

Electric Reliability Council of Texas, Inc. (ERCOT) files with the Public Utility Commission of Texas (Commission) revisions to the ERCOT Nodal Protocols.

Summary of Revisions

In accordance with the process set forth in Section 21 of the ERCOT Protocols, ERCOT adopted Nodal Protocol Revision Requests (NPRRs) 1149 (effective upon system implementation), 1153 (Phase 1 effective April 1, 2023 and Phase 2 effective upon system implementation), 1144, 1147, 1151, 1158, and 1159. These NPRRs were developed in the ERCOT committee process; on February 28, 2023, the ERCOT Board of Directors voted to recommend approval. Additionally, consistent with the requirement in PURA § 39.151(d) that a Protocol revision may not take effect before Commission approval, the Commission approved these revisions at an open meeting on March 23, 2023. These NPRRs are described below.

NPRR	Description	ERCOT Nodal Protocol Sections Modified
1144	**Station Service Backup Power Metering**. This NPRR amends the requirement of having all energy utilized at generating Facilities be recorded through an ERCOT-Polled Settlement (EPS) Meter so that relatively insignificant loads, like backup station service power, can be exempt from measurement through an EPS Meter.	Section 10, Subsection 10.3.2.3 (Attachment A)
1147	**Update and Improve Notification and Evaluation Processes Associated with Reliability Must-Run (RMR).** This NPRR: adds a 20 MW capacity	Section 3, Subsections 3.14.1.1, 3.14.1.2, 3.14.1.5, 3.14.1.9, and 3.14.1.10

	threshold for conducting a Reliability Must-Run (RMR) reliability analysis; requires that an RMR study be conducted when a Resource Entity gives notice that a Generation Resource is ceasing operation permanently due to a Forced Outage; and updates Section 22, Attachment E to require Resource Entity to provide information about deactivation of Transmission Facilities as part of the suspension of operations of the unit.	(Attachment B) Section 22, Attachment E (Attachment C)
1149 **(effective upon system implementation)**	**Implementation of Systematic Ancillary Service Failed Quantity Charges.** This NPRR charges a Qualified Scheduling Entity (QSE) an Ancillary Service failed quantity if the Ancillary Service Supply Responsibility held by the QSE is not met by Resources in their portfolio in Real-Time, based on a comparison of their Real-Time telemetry. The charges will be done systematically without ERCOT control room operators having to take additional action.	Section 2, Subsection 2.1 (Attachment D) Section 4, Subsection 4.4.7.4 (Attachment E) Section 6, Subsections 6.3.2, 6.4.1, 6.4.9.1.3, 6.7.3, and 6.7.5 (Attachment F)
1151	**Protocol Revision Subcommittee Meeting Requirement.** This NPRR eliminates the Protocol requirement to hold at least one Protocol Revision Subcommittee (PRS) meeting per month.	Section 21, Subsection 21.3 (Attachment G)
1153 **(Phase 1 effective April 1, 2023; Phase 2 effective upon system implementation)**	**ERCOT Fee Schedule Changes.** This NPRR changes the ERCOT Fee Schedule by adding two currently existing fees to the Fee Schedule (public information request labor fees and ERCOT training fees); creating a registration fee of $500 for Resource Entities, Transmission or Distribution Service Providers (TDSPs), and Subordinate Qualified Scheduling Entities (Sub-QSEs); removing the	Section 9, Subsection 9.16.2 (Attachment H) ERCOT Fee Schedule (Attachment I) Section 23, Form G (Attachment J)

	current value of the ERCOT System Administration Fee; deleting the map sales fee; and restructuring three existing fees on the Fee Schedule (Generator Interconnection or Modification (GIM) fees, Full Interconnection Study (FIS) Application fees, and Wide Area Network (WAN) fees).	Section 23, Form I (Attachment K) Section 23, Form J (Attachment L)
1158	**Remove Sunset Date for Weatherization Inspection Fees.** This NPRR eliminates the Weatherization Inspection fee's sunset date on the ERCOT Fee Schedule and changes the invoicing period of such fees from a quarterly to a semiannual basis.	ERCOT Fee Schedule (Attachment I)
1159	**Related to RMGRR171, Changes to Transition Process that Require Opt-in MOU or EC that are Designating POLR to provide Mass Transition Methodology to ERCOT.** This NPRR provides needed references to the Retail Market Guide to account for Texas Standard Electronic Transaction (TX SET) processing options for Municipally Owned Utility (MOU) or Electric Cooperative (EC) service areas, in alignment with RMGRR171.	Section 15, Subsection 15.1.10.1 (Attachment M) Section 19, Subsection 19.3.1 (Attachment N)

The changes to the Nodal Protocol language as revised by the above NPRRs are shown in Attachments A through N.

The ERCOT Nodal Protocols, including these revisions, may be accessed on ERCOT's website at http://www.ercot.com/mktrules/nprotocols/index.html.

Dated: March 31, 2023

Respectfully submitted,

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ATTORNEYS FOR ELECTRIC RELIABILITY
COUNCIL OF TEXAS, INC.

LIST OF ATTACHMENTS

ERCOT Nodal Protocols

Section 10: Metering

April 1, 2023

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10 METERING

10.1 Overview

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

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

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

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

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

10.2 Scope of Metering Responsibilities

10.2.1 QSE Real-Time Metering

(1) The Qualified Scheduling Entity's (QSE's) responsibility for Real-Time metering requirements is contained in Section 6.5.5.2, Operational Data Requirements.

10.2.2 TSP and DSP Metered Entities

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

(a) All Loads using the ERCOT System;

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

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

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

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

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

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

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

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

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

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

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

10.2.3 ERCOT-Polled Settlement Meters

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

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

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

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

(d) Generation participating in any Ancillary Service market;

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

(f) Direct Current Ties (DC Ties);

(g) DG where there is an energy storage Load Resource that has associated Wholesale Storage Load (WSL);

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

(g) Metering required to determine the Wholesale Storage Load (WSL) or Non-WSL Settlement Only Charging Load associated to a Settlement Only Distribution Energy Storage System (SODESS) or Settlement Only Transmission Energy Storage System (SOTESS);

(h) Metering required to determine WSL associated with an Energy Storage Resource (ESR); and

(i) Metering required to determine the Non-WSL ESR Charging Load.

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

10.2.3.1 Entity EPS Responsibilities

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

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

(b) A TSP or DSP shall have EPS Metering Facilities installed and maintained under the supervision of a TSP or DSP "EPS Meter Inspector," which is defined as an employee or agent of the TSP or DSP who has received EPS training from ERCOT, and is described further herein. This requirement does not apply to Resource Entity-owned Metering Facilities used to measure, calculate, or telemeter ESR auxiliary Load pursuant to Section 10.2.4, Resource Entity Calculation and Telemetry of ESR Auxiliary Load Values.

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

(b) A TSP or DSP shall have EPS Metering Facilities installed and maintained under the supervision of a TSP or DSP "EPS Meter Inspector," which is defined as an employee or agent of the TSP or DSP who has received EPS training from ERCOT, and is described further herein. This requirement does not apply to Resource Entity-owned Metering Facilities used to measure, calculate, or telemeter ESR, SODESS, or SOTESS auxiliary Load pursuant to Section 10.2.4, Resource Entity Calculation and Telemetry of ESR, SODESS, or SOTESS Auxiliary Load Values.

(c) Each TSP and DSP shall install, control, and maintain the meters, recorders, instrument transformers, wiring, communications, and other miscellaneous equipment required to measure electrical energy, as described in this Section and SMOG, except for Resource Entity-owned equipment used to measure, calculate, or telemeter an auxiliary Load value for an ESR pursuant to Section 10.2.4.

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

(c) Each TSP and DSP shall install, control, and maintain the meters, recorders, instrument transformers, wiring, communications, and other miscellaneous equipment required to measure electrical energy, as described in this Section and SMOG, except for Resource Entity-owned equipment used to measure, calculate, or telemeter an auxiliary Load value for an ESR, SODESS, or SOTESS pursuant to Section 10.2.4.

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

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

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

10.2.4 Resource Entity Calculation and Telemetry of ESR Auxiliary Load Values

(1) When the Resource Entity certifies, the interconnecting TDSP confirms by approving the metering design, and, based on the information provided by the TDSP as part of the EPS Design Proposal, ERCOT agrees that metering of an ESR's WSL separate from the ESR's auxiliary Load is not feasible based on the ESR's physical design, the Resource Entity for that ESR shall be permitted to calculate the auxiliary Load using measurements from its own internal sensors and telemeter a Real-Time aggregated value for that Load to the TDSP's EPS Meter. The Resource Entity may telemeter a zero Load value only when the ESR is discharging more than the calculated auxiliary Load. The methodology by which the auxiliary Load is calculated is subject to ERCOT approval.

(2) An officer of the Resource Entity shall annually attest to the methodology and validity of the auxiliary Load calculation, as further described in the SMOG. The Resource Entity shall include with its annual attestation the findings of an independent audit performed by a registered Texas Professional Engineer confirming the auxiliary Load calculation does not understate the Load value. The audit shall be based on laboratory testing that reflects the anticipated field conditions of the same model of sensor as that used by the Resource Entity or validation using measurements by other devices over the past year, as further described in the SMOG. The audit shall evaluate the impact of any degradation in accuracy of the sensors over time.

(3) If the Resource Entity is unable to provide the attestation and audit findings meeting the requirements of paragraph (2) above, it shall either reconfigure the Resource Entity's site and resubmit its meter design within 30 days to allow for separately metering the WSL, or forfeit WSL treatment.

(4) ERCOT may conduct an audit of the Resource Entity's processes, equipment, and calculation of the auxiliary Load.

(5) The TSP or DSP shall assign all costs required for separately metering the auxiliary Load for WSL treatment to the EPS Meter to the Resource Entity.

[NPRR995: Replace Section 10.2.4 above with the following upon system implementation:]

10.2.4 Resource Entity Calculation and Telemetry of ESR, SODESS, or SOTESS Auxiliary Load Values

(1) When the Resource Entity certifies, the interconnecting TDSP confirms by approving the metering design, and, based on the information provided by the TDSP as part of the EPS Design Proposal, ERCOT agrees that metering of an ESR's WSL separate from the ESR's, SODESS's, or SOTESS's auxiliary Load is not feasible based on the ESR's, SODESS's, or SOTESS's physical design, the Resource Entity for that ESR, SODESS, or SOTESS shall be permitted to calculate the auxiliary Load using measurements from its own internal sensors and telemeter a Real-Time aggregated value for that Load to the TDSP's EPS Meter. The Resource Entity may telemeter a zero Load value only when the ESR, SODESS, or SOTESS is discharging more than the calculated auxiliary Load. The methodology by which the auxiliary Load is calculated is subject to ERCOT approval.

(2) An officer of the Resource Entity shall annually attest to the methodology and validity of the auxiliary Load calculation, as further described in the SMOG. The Resource Entity shall include with its annual attestation the findings of an independent audit performed by a registered Texas Professional Engineer confirming the auxiliary Load calculation does not understate the Load value. The audit shall be based on laboratory testing that reflects the anticipated field conditions of the same model of sensor as that used by the Resource Entity or validation using measurements by other devices over the past year, as further described in the SMOG. The audit shall evaluate the impact of any degradation in accuracy of the sensors over time.

(3) If the Resource Entity is unable to provide the attestation and audit findings meeting the requirements of paragraph (2) above, it shall either reconfigure the Resource Entity's site and resubmit its meter design within 30 days to allow for separately metering the WSL or forfeit WSL treatment.

(4) ERCOT may conduct an audit of the Resource Entity's processes, equipment, and calculation of the auxiliary Load.

(5) The TSP or DSP shall assign all costs required for separately metering the auxiliary Load for WSL treatment to the EPS Meter to the Resource Entity.

10.2.4.1 Responsibilities for Resource Entity Calculation and Telemetry of ESR Auxiliary Load Values

(1) For each site at which a Resource Entity telemeters its auxiliary Load value, as permitted by Section 10.2.4, Resource Entity Calculation and Telemetry of ESR Auxiliary Load Values:

(a) The Resource Entity shall:

(i) Provide supporting information on the equipment, configuration, drawings and processes used to calculate the telemetry signal, including supporting information on the calculation of the telemetry signal for inclusion in the EPS Design Proposal.

(ii) Provide documentation of the auxiliary Load calculation methodology as defined in this Section and the SMOG.

(iii) Install, control, and maintain the sensors, instrumentation, wiring, communications, and other equipment required to calculate and provide the telemetry signal.

(iv) Provide and update contact information for a person designated for communication regarding the auxiliary Load supporting information and data.

(v) Act in accordance with any TDSP requirements concerning EPS Meters and Metering Facilities in the Protocols and SMOG that pertain to the following issues:

(A) Calculation of Load values and data estimation issues;

(B) The provision of notice to ERCOT regarding any outage or any other issue affecting the accuracy of the Load calculation or the availability of the telemetry of the Load value; and

(C) The implementation of any proposed change to the calculation or equipment, as documented in the EPS Design Proposal; and

(vi) Provide any information requested by ERCOT or the TDSP with respect to the measurement, calculation, and/or telemetry of the auxiliary Load value.

(b) The interconnecting TDSP shall:

(i) Use an EPS Meter to calculate 15-minute energy values from the Resource Real-Time telemetry signal for the auxiliary Load and store the data in the EPS Meter for retrieval by the ERCOT Meter Data Acquisition System (MDAS); and

(ii) Include an auxiliary Load metering point on the EPS Design Proposal that represents the calculation of the telemetry signal.

(c) ERCOT shall:

(i) Review the Resource-provided data on the calculation of the telemetry signal submitted as part of the EPS Design Proposal to ensure compliance with defined rules in this Section and the SMOG; and

(ii) Request assistance and information from the Resource-designated contact for items related to the telemetry.

[NPRR995: Replace Section 10.2.4.1 above with the following upon system implementation:]

10.2.4.1 Responsibilities for Resource Entity Calculation and Telemetry of ESR, SODESS, or SOTESS Auxiliary Load Values

(1) For each site at which a Resource Entity telemeters its auxiliary Load value, as permitted by Section 10.2.4, Resource Entity Calculation and Telemetry of ESR, SODESS, or SOTESS Auxiliary Load Values:

(a) The Resource Entity shall:

(i) Provide supporting information on the equipment, configuration, drawings and processes used to calculate the telemetry signal, including supporting information on the calculation of the telemetry signal for inclusion in the EPS Design Proposal.

(ii) Provide documentation of the auxiliary Load calculation methodology as defined in this Section and the SMOG.

(iii) Install, control, and maintain the sensors, instrumentation, wiring, communications, and other equipment required to calculate and provide the telemetry signal.

(iv) Provide and update contact information for a person designated for communication regarding the auxiliary Load supporting information and data.

(v) Act in accordance with any TDSP requirements concerning EPS Meters and Metering Facilities in the Protocols and SMOG that pertain to the following issues:

(A) Calculation of Load values and data estimation issues;

(B) The provision of notice to ERCOT regarding any outage or any other issue affecting the accuracy of the Load calculation or the availability of the telemetry of the Load value; and

(C) The implementation of any proposed change to the calculation or equipment, as documented in the EPS Design Proposal; and

(vi) Provide any information requested by ERCOT or the TDSP with respect to the measurement, calculation, and/or telemetry of the auxiliary Load value.

(b) The interconnecting TDSP shall:

(i) Use an EPS Meter to calculate 15 minute energy values from the Resource Real-Time telemetry signal for the auxiliary Load and store the data in the EPS Meter for retrieval by the ERCOT Meter Data Acquisition System (MDAS); and

(ii) Include an auxiliary Load metering point on the EPS Design Proposal that represents the calculation of the telemetry signal.

(c) ERCOT shall:

(i) Review the Resource-provided data on the calculation of the telemetry signal submitted as part of the EPS Design Proposal to ensure compliance with defined rules in this Section and the SMOG; and

(ii) Request assistance and information from the Resource-designated contact for items related to the telemetry.

10.3 Meter Data Acquisition System (MDAS)

10.3.1 Purpose

(1) The Meter Data Acquisition System (MDAS) will be used:

(a) By ERCOT to obtain and receive Revenue Quality Meter data from the ERCOT-Polled Settlement (EPS) Meters and Settlement Quality Meter Data from the Transmission Service Provider (TSP) and Distribution Service Provider (DSP) for Settlement and billing purposes; and,

(b) To populate the ERCOT Data Archive used by Market Participants or their agents with authority to access Settlement Quality Meter Data held by ERCOT.

10.3.2 ERCOT-Polled Settlement Meters

(1) Each TSP and DSP shall, in accordance with these Protocols and the Settlement Metering Operating Guide (SMOG), provide ERCOT-approved metering communication equipment and connection to permit ERCOT access to the TSP's or DSP's EPS Meters.

(2) ERCOT shall retrieve meter data electronically and automatically by MDAS. ERCOT may also collect meter data on demand.

10.3.2.1 Generation Resource Meter Splitting

(1) Each Generation Resource meter must be represented by only one Qualified Scheduling Entity (QSE), except that a jointly owned Generation Resource unit or group of Generation Resources may split the net generation output into two or more Split Generation Resources for a Resource Entity. Each Resource Entity representing a Split Generation Resource may have its energy and capacity scheduled through a separate QSE. For purposes of this paragraph, a jointly owned Generation Resource unit or group of Generation Resources shall also include the San Miguel and Gibbons Creek power projects and Intermittent Renewable Resources (IRRs) such as wind and solar generation.

(2) When a Generation Resource that has been split to function as two or more Split Generation Resources is registered with ERCOT, the Resource Entities representing the Split Generation Resources shall be required to submit a percentage allocation of the Generation Resource to be used to determine the capacity available at each Split Generation Resource.

(3) When a Generation Resource that has been split to function as two or more Split Generation Resources is registered with ERCOT, the owners of the Generation Resource shall submit all required ERCOT Facility registration documentation and an ERCOT-approved splitting agreement executed by an Authorized Representative from each owning Resource Entity. Such agreement shall contain a defined and fixed ownership percentage as among the owning Resource Entities. ERCOT shall establish this Generation Resource as a "split," essentially establishing Split Generation Resource meters. Generation splitting based on a static ratio is not permitted. Generation splitting requires Real-Time splitting signals.

10.3.2.1.1 Split Generation Resource Metering Real-Time Signal

(1) When a Split Generation Resource is registered with ERCOT, the QSE representing the Split Generation Resource shall provide ERCOT with a Real-Time signal of the MW of generation for the Split Generation Resource. The Real-Time MW signals must be revised every scan cycle and must represent the QSE's Split Generation Resource in positive MW.

(2) ERCOT shall integrate the Real-Time MW signals and provide a MWh value for each 15-minute interval for each Split Generation Resource.

(3) The settlement system shall use the integrated MWh per interval value to calculate the percentage breakdowns to be applied to the actual metered MWh values retrieved from the EPS Metering Facility.

10.3.2.1.2 Allocating EPS Metered Data to Split Generation Resource Meters

(1) ERCOT shall poll the EPS Metering Facilities related to the actual Generation Resource and store the meter data at 15-minute intervals. This metering data must be validated, edited, estimated, and compensated for losses, as necessary, and be netted as required. This resulting data must then have the Split Generation Resource ratios applied to assign the generation to the QSE representing each owner of the Split Generation Resources. The MWh quantities of the Split Generation Resources must be used in all Settlement calculations and reports.

(2) The following example illustrates the splitting of the generation data:

Splitting Example 1

Integrated values from ERCOT systems						**Actual Metered MWh**	**Data to be Used in Settlement**		
Interval Ending	**RID1 (MWh)**	**RID2 (MWh)**	**RID3 (MWh)**	**Total MWh**	**% Ratios Rid 1,2,3**		**Split MWh**	**Split MWh**	**Split MWh**
13:15	10	20	10	40	25, 50, 25	52	13	26	13

10.3.2.1.3 Processing for Missing Dynamic Split Generation Resource Signal

(1) For any interval when ERCOT has not received a Real-Time signal for any one of the Split Generation Resources, ERCOT shall use the last valid percentage ratio for a completed interval.

Splitting Example 2

Integrated values from ERCOT systems						**Actual Metered MWh**	**Data to be Used in Settlement**		
Interval Ending	**RID1 (MWh)**	**RID2 (MWh)**	**RID3 (MWh)**	**Total MWh**	**% Ratios Rid 1,2,3**		**Split MWh**	**Split MWh**	**Split MWh**
13:15	10	20	10	40	25, 50, 25	52	13	26	13
13:30	NA	21	10	NA	Ratio Above	55	13.75	27.5	13.75
13:45	NA	22	10	NA	Ratio Above	48	12	24	12

10.3.2.1.4 Calculating the Split Generation Resource Ratio

(1) For Split Generation Resources, ERCOT shall provide for Settlement the net MWh value for each 15-minute interval. This value is the MWh accumulated based on the MW value over each scan cycle. ERCOT shall use a standard “integration” mechanism to perform this function.

(2) For Settlement, ERCOT shall use the integrated data to determine the allocation ratio as the integrated share of each signal divided by the integrated total of signals.

10.3.2.1.5 Split Generation Resource Data Made Available to Market Participants

(1) Market Participants shall have access to allocated generation output and ratio data only for Split Generation Resources that they represent.

10.3.2.1.6 Allocating EPS Metered Data to Generator Owners When It Is Net Load

(1) EPS Generation Resource sites that are netted by ERCOT may have multiple Competitive Retailers (CRs) associated with the Load. ERCOT shall poll the EPS metering facilities related to the actual Generation Resource facility and store the meter data at 15-minute intervals. ERCOT shall perform validation, editing, estimation, compensation for losses as necessary, and netting as required for EPS metering data. For intervals when data is net Load, the fixed ownership percentages stored in the asset database must be used to allocate the consumption to multiple Electric Service Identifiers (ESI IDs). The consumption quantities for the ESI IDs must be used in all energy settlement calculations and reports.

10.3.2.2 Loss Compensation of EPS Meter Data

(1) Where the EPS Meter is not located at the Point of Interconnection (POI) to the ERCOT Transmission Grid, actual metered consumption must be adjusted for line and transformation losses to the POI in accordance with SMOG Section 8, Transformer and Line Loss Compensation Factors. The preferred method for loss compensation and correction is via internal meter programming.

(2) Recognizing the fact that some locations may not have the total functionality necessary to perform internal compensation, the Data Aggregation System (DAS) must have the functionality to perform approved loss compensation as necessary. ERCOT shall retain the discretion to allow or deny the continued use of this type of metering.

(3) No meter may be compensated internally for losses more than once. ERCOT may compensate multiple meters prior to netting to the POI. Pulse communications transfer of data between meters is not allowed.

10.3.2.3 Generation Netting for ERCOT-Polled Settlement Meters

(1) Each Generation Resource and Settlement Only Generator (SOG) and each Load that is designated to be netted with that Generation Resource or SOG, including construction and maintenance Load that is netted with existing generation auxiliaries, must be physically metered at its POI to the ERCOT Transmission Grid or Service Delivery Point, or, in accordance with Section 10.3.2.2, Loss Compensation of EPS Meter Data, loss-compensated to its POI to the ERCOT Transmission Grid. Interval Data Recorders

(IDRs) must be used to determine generator output or Load usage. In the intervals where the generation output exceeds the Load, the net must be settled as generation. In the intervals where the Load exceeds the generation output, the net must be settled as Load, and carry any applicable Load shared charges and credits.

(2) For Settlement purposes, netting is not allowed except under the configurations described in paragraphs (2)(a) through (2)(e) below, and only if the service arrangement is otherwise lawful. ERCOT has no obligation to independently determine whether a site configuration that includes both Loads and Generation Resource(s) or SOGs complies with Public Utility Regulatory Act (PURA) or the Public Utility Commission of Texas (PUCT) Substantive Rules, and ERCOT's approval of a metering proposal for such a site is not a verification of the legality of that arrangement:

(a) Single POI or Service Delivery Point;

(b) Transmission-level interconnections where all POIs are located at the same substation, at the same voltage, and under normal operating conditions, are interconnected through common electrical equipment such as circuit breakers, connecting cables, bus bars, switches/isolators. Qualifying station arrangements include, but are not limited to, Generation and Load connected in a line bus, ring bus, double-breaker, or breaker-and-a-half configuration;

(c) Multiple POIs where the Loads and generator output are electrically connected to a common switchyard, as defined in paragraph (7) below. In addition, there must be sufficient generator capacity to serve all plant Loads for netting to occur;

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

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

(3) For Energy Storage Resource (ESR) sites, Wholesale Storage Load (WSL) must be separately metered from all other Loads and generation, and must be metered using EPS Metering Facilities.

(a) For configurations where the Resource Entity telemeters an auxiliary Load value to the EPS Meter:

(i) The total energy into the ESR must be separately metered from all other Loads and generation, and must be metered using EPS Metering Facilities; and

(ii) The auxiliary Load energy shall be stored in the EPS Meter's IDR, per channel assignments defined in the SMOG.

(b) For configurations where the WSL is not at a POI, it must be metered behind a single POI metering point, per the requirements in paragraph (3) or (3)(a) above; and

(c) WSL for a compressed air energy storage Load Resource is exempt from the requirement to be electrically connected to a common switchyard, as defined in paragraph (7) below.

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

(3) For Energy Storage Resource (ESR), Settlement Only Distribution Energy Storage System (SODESS), or Settlement Only Transmission Energy Storage System (SOTESS) sites, Wholesale Storage Load (WSL) must be separately metered from all other Loads and generation, and must be metered using EPS Metering Facilities.

(a) For configurations where the Resource Entity telemeters an auxiliary Load value to the EPS Meter:

(i) The total energy into the ESR, SODESS, or SOTESS must be separately metered from all other Loads and generation, and must be metered using EPS Metering Facilities; and

(ii) The auxiliary Load energy shall be stored in the EPS Meter's IDR, per channel assignments defined in the SMOG.

(b) For configurations where the WSL is not at a POI, it must be metered behind a single POI metering point, per the requirements in paragraph (3) or (3)(a) above; and

(c) WSL for a compressed air energy storage Load Resource is exempt from the requirement to be electrically connected to a common switchyard, as defined in paragraph (7) below.

(4) ERCOT shall maintain descriptions of the Metering Facilities of all common switchyards that contain multiple POIs of Loads (ESI IDs) and generation meters (EPS). The description is limited to identifying the Entities within a common switchyard and a

simplified diagram showing the metering configuration of all Supervisory Control and Data Acquisition (SCADA) and Settlement Metering points.

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

(6) Notwithstanding the requirements of paragraph (5) above, auxiliary Load(s) connected to the station service transformer not to exceed 500 kW in aggregate shall be permitted an additional electrical connection to a TSP's or DSP's Facilities through a separately metered Transmission and/or Distribution Service Provider (TDSP) read metering point. In locations subject to multiple certificated service areas, the Resource Entity shall notify each DSP that has the right to serve in the service area of the proposed connection. This configuration requires mutual agreement between the connecting TSP, DSP, and Resource Entity, and the connection shall be achieved through an open transition load transfer switch listed for emergency service and shall only be used in emergency and maintenance situations.

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

(8) Notwithstanding any other provision in this Section, for any Generation Resource or ESR that is configured to serve a Customer Load as part of a Private Microgrid Island (PMI), the connection to the Customer Load in the PMI configuration shall be located behind the EPS metering point at the Resource's POI. For a PMI configuration that includes an ESR that is receiving WSL treatment for charging Load, an EPS Meter shall be located to measure the ESR's gross output net of any internal telemetered auxiliary Load, and a separate TDSP ESI ID (for nodal Settlement) with a Load Serving Entity (LSE) association must be established for the site prior to service of any Load.

[NPRR945: Insert paragraph (9) below upon system implementation:]

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

10.3.2.4 Reporting of Net Generation Capacity

(1) Each Resource Entity with either a Generation Resource or Settlement Only Transmission Self-Generator (SOTSG) in a Private Use Network shall complete and submit the declaration in Section 22, Attachment L, Declaration of Private Use Network Net Generation Capacity Availability, to ERCOT by February 1 of each year, stating its projected annual changes in net generation capacity available to the ERCOT Transmission Grid for May 31 of the previous calendar year to May 31 of the current calendar year, and annual changes as of May 31 for the next ten subsequent years. ERCOT will use the aggregated capacity forecasts for the Report on Capacity, Demand and Reserves in the ERCOT Region, pursuant to Section 3.2.6.2.2, Total Capacity Estimate.

10.3.3 TSP or DSP Metered Entities

10.3.3.1 Data Responsibilities

(1) Each TSP and DSP shall be responsible for the following:

(a) Providing consumption data for each ESI ID and RID on at least a monthly basis according to the data timeliness and accuracy standards defined in this Section and in the SMOG;

(b) Providing start date, stop date, ESI ID or RID, and consumption data in kWh as well as an identifier for "estimated" reads as applicable;

(c) Submitting a single Demand value for each non-IDR ESI ID that has a Demand register to ERCOT if, and only if, a Demand value is required for TSP or DSP tariffs or for CR Customer billing. If the CR and TSP or DSP do not require a Demand value, then the TSP or DSP shall not submit a Demand value to ERCOT even if the meter has a Demand register;

(d) Validation, Editing, and Estimation of meter data (VEE) according to the standards in this Section before submitting data to the settlement process;

(e) Calculating consumption for any unmetered services by ESI ID and submitting such data monthly to ERCOT, subject to ERCOT audit. These calculations must be made pursuant to TSP and DSP-approved tariffs; and

(f) Metering all Loads, unless the Load meets one of the following criteria:

(i) Energy consumption by substation Facilities and equipment for the purpose of transporting electricity (e.g., substation transformers, fans, etc.).

(ii) Unmetered energy consumption represented by an ERCOT-approved Load Profile; or

(iii) Energy charge and discharge and associated losses for the ERCOT Board-approved storage devices installed as part of a transmission reliability project for the Presidio substation Facilities.

10.3.3.2 Retail Load Meter Splitting

(1) Retail Service Delivery Points with Loads above 1 MW may split their actual meter data into a maximum of four consumption values with each value being assigned a unique ESI ID; provided, however, that if a Customer is using Provider of Last Resort (POLR) or the "Price-to-Beat" retail service, such Customer may not split its meter signal among multiple CRs through this Section.

10.3.3.2.1 Retail Customer Load Splitting Mechanism

(1) Customer meter data may be split into separate ESI IDs by the installation of a programmable signal splitter that would take the master meter signal and split it into no more than four separate values that must at all times equal the total output of the master meter signal. Splitting of Customer meter data must meet the following requirements:

(a) The signal splitter may be programmed to split the Load in any way the Customer chooses, provided that such splitting results in positive Load;

(b) The Customer, or its CR(s), shall provide the signal splitter and shall be responsible for all costs of installing, maintaining, and operating the signal splitter, any associated equipment, and communications;

(c) The TSP or DSP shall be responsible for approving the specifications and installation of any signal splitting devices;

(d) IDRs shall be required on the master Customer Load meter and each of the split channels for verification and settlement purposes;

(e) The TSP or DSP metering system recording such split signals (four ESI IDs) may be required to be redundant if so provided by TSP or DSP tariffs;

(f) The split signals must be recorded in Real-Time and cannot be altered or substituted later in time;

(g) One Entity shall be designated to pay the total TSP and/or DSP charges for the Customer; and

(h) Switching of CRs for the individual split-metered Customers shall comply with the registration procedures in Section 19, Texas Standard Electronic Transaction.

10.3.3.2.2 TSP and DSP Responsibilities Associated with Retail Customer Load Splitting

(1) Each consumption value from a Customer Load split meter shall be assigned a separate ESI ID by the TSP or DSP. Each ESI ID may be assigned to a separate CR. The master meter may not be assigned an ESI ID.

(2) The TSP or DSP shall send interval data for each ESI ID for the ERCOT settlement system.

(3) The TSP or DSP shall be responsible for verifying that the sum of the split ESI ID IDR data equals the total IDR value from the master meter.

10.3.3.2.3 ERCOT Requirements for Retail Load Splitting

(1) ERCOT shall settle all ESI IDs in the same manner.

(2) ERCOT shall not receive or process the IDR data associated with the master meter.

10.3.3.3 Submission of Settlement Quality Meter Data to ERCOT

(1) Settlement Quality Meter Data shall be submitted to ERCOT on a periodic cycle, but no later than monthly:

(a) For provisioned Advanced Meters and Municipally Owned Utility (MOU) / Electric Cooperative (EC) Non-BUSIDRRQ IDRs, Settlement Quality Meter Data will be submitted using an ERCOT specified file format for the interval data only, which will be used for Settlement.

(i) The monthly non-interval total consumption and demand (if applicable) values for these ESI IDs shall be provided to ERCOT and LSEs using the appropriate Texas Standard Electronic Transactions (TX SETs) in order to effectuate the registration transactions outlined in Section 15, Customer Registration.

(ii) These non-interval total consumption and demand values will not be used for Settlement.

(b) For all other meters, Settlement Quality Meter Data will be submitted using the appropriate TX SET.

(2) Each TSP or DSP shall ensure that consumption meter data submitted to ERCOT is in intervals of:

(a) 15-minutes for those ESI IDs and RIDs served by IDRs; and

(b) Monthly or on an ERCOT-approved meter reading cycle for non-IDRs.

(3) The Settlement Quality Meter Data submitted by TSP or DSP must be in kWh and kVArh values (as applicable).

10.3.3.3.1 Past Due Data Submission

(1) ERCOT shall provide a report to the appropriate TSP and DSP for any ESI ID or RID for which consumption data has not been received in the past 38 days. Upon receipt of the missing consumption data report, the TSP or DSP shall have two Business Days to submit the missing consumption data.

10.4 Certification of EPS Metering Facilities

(1) Each Transmission Service Provider (TSP) and Distribution Service Provider (DSP) shall certify ERCOT-Polled Settlement (EPS) Metering Facilities in a manner approved by ERCOT.

10.4.1 Overview

(1) This Section describes the steps that a TSP or DSP shall use to certify each EPS Metering Facility and the steps ERCOT shall use to approve each EPS Metering Facility. This Section also describes the manner in which EPS Metering Facility approval requests must be made to ERCOT.

10.4.2 EPS Design Proposal Documentation Required from the TSP or DSP

(1) Before installation of new EPS Meters, TSP or DSP shall provide ERCOT with an EPS Design Proposal of the Metering Facilities being considered for ERCOT approval as EPS Meter Facilities. An "EPS Design Proposal" is the documentation required on the form available on the ERCOT website. Included one line drawings must be dated, detailed, bear the current drawing revision number, and show all devices which contribute to the burden in the metering circuits. Other information may also be required by ERCOT for review regarding the meter and related installation and Facilities; such additional information shall be promptly provided to ERCOT by the TSP or DSP upon request of ERCOT.

10.4.2.1 Approval or Rejection of an EPS Design Proposal for EPS Metering Facilities

(1) ERCOT may unconditionally approve, conditionally approve, or reject an EPS Design Proposal.

10.4.2.1.1 Unconditional Approval

(1) If ERCOT unconditionally approves an EPS Design Proposal, then ERCOT shall promptly notify the TSP or DSP that the EPS Design Proposal has been approved. The TSP or DSP may then commence installation of the EPS Metering Facilities in accordance with the EPS Design Proposal.

10.4.2.1.2 Conditional Approval

(1) Notification of Conditional Approval:

If ERCOT conditionally approves an EPS Design Proposal, then ERCOT shall promptly notify the TSP or DSP that the EPS Design Proposal has been conditionally approved. It shall set forth in such Notice the conditions on which approval is granted and the time period in which each such condition must be satisfied by the TSP or DSP.

(2) Ability to Satisfy Conditions:

If the TSP or DSP disputes any condition imposed by ERCOT, the TSP or DSP must promptly notify ERCOT of its concerns and provide ERCOT with the reasons for its concerns. If the TSP or DSP provides ERCOT such Notice, ERCOT may amend or withdraw any of the conditions on which it granted its approval or ERCOT may require the TSP or DSP to satisfy other conditions. ERCOT and the TSP or DSP shall use good faith efforts to reach agreement on accomplishing the installation.

(3) Notification of Satisfaction of Conditions:

The TSP or DSP shall promptly notify ERCOT when each condition in the approval has been satisfied and provide to ERCOT any information reasonably requested by ERCOT as evidence that such condition has been satisfied.

(4) Confirmation of Satisfaction of Conditions:

If ERCOT determines that a condition has been satisfied, then ERCOT shall provide the TSP or DSP written confirmation that the condition has been satisfied.

(5) Unsatisfied Conditions:

If ERCOT determines that a condition has not been satisfied, ERCOT shall notify the TSP or DSP that it does not consider the condition satisfied and shall set out in such Notice the reason(s) that it does not consider the condition satisfied. If, after using good faith efforts, ERCOT and the TSP or DSP are unable to agree on whether the condition is satisfied, either Entity may refer the dispute to the Alternative Dispute Resolution (ADR) Procedures as described in Section 20, Alternative Dispute Resolution Procedure.

10.4.2.1.3 Rejection

(1) If ERCOT rejects an EPS Design Proposal, then ERCOT shall promptly notify the TSP or DSP that the EPS Design Proposal has been rejected and shall set forth the reasons for its rejection. The TSP or DSP shall submit to ERCOT a revised EPS Design Proposal after receiving such Notice. If ERCOT rejects for a second time an EPS Design Proposal submitted by a TSP or DSP with respect to the same or similar Notice issued by ERCOT as described above, then ERCOT and the TSP or DSP shall use good faith efforts to reach agreement on the requirements and disputed items. In the absence of agreement either Entity may refer the dispute to the ADR Procedures as described in Section 20, Alternative Dispute Resolution Procedure.

10.4.3 Site Certification Documentation Required from the TSP or DSP EPS Meter Inspector

(1) A TSP or DSP EPS Meter Inspector shall complete an ERCOT site certification form for each set of EPS Metering Facilities that it inspects. The site certification form is the official form used to document whether EPS Metering Facilities meet ERCOT criteria.

(2) The TSP or DSP EPS Meter Inspector shall promptly notify ERCOT and document any discrepancy between ERCOT approved EPS Design Proposal on file and the actual Metering Facilities inspected by the TSP or DSP EPS Meter Inspector.

(3) The TSP or DSP shall provide the documents as outlined in Settlement Metering Operating Guide (SMOG) for each set of EPS Metering Facilities being considered for ERCOT approval.

10.4.3.1 Review by ERCOT

(1) ERCOT shall review the ERCOT site certification documentation prepared by the TSP or DSP EPS Meter Inspector within 45 days of receipt. If ERCOT finds that this data is incomplete or demonstrates that the EPS Metering Facilities fail to meet the standards contained within this Section or the SMOG, ERCOT shall promptly provide written or electronic notice of the deficiencies to the TSP or DSP.

(2) ERCOT shall notify the TSP or DSP of the approval of the Metering Facility. ERCOT shall return a copy of the schematic drawings, and a copy of the ERCOT site certification form marked by ERCOT as approved. ERCOT shall retain a copy of these documents.

10.4.3.2 Provisional Approval

(1) If ERCOT finds that the documentation: provided by the TSP or DSP is incomplete or demonstrates that the EPS Metering Facility fails to meet the standards contained within this Section and SMOG; then ERCOT may, elect to issue a provisional approval for the

Metering Facility. The terms and conditions on which such provisional approval is issued shall be at ERCOT's discretion and shall be defined for the TSP or DSP. ERCOT shall not issue an approval until such time as all of the conditions of the provisional approval have been fulfilled to the satisfaction of ERCOT. ERCOT shall post any provisional approvals on the ERCOT website on a quarterly basis.

10.4.3.3 Obligation to Maintain Approval

(1) Once an EPS Metering Facility has been installed, it is the responsibility of the TSP or DSP to ensure that the EPS Metering Facility complies with the approval criteria referred to in this Section and the SMOG.

10.4.3.4 Revocation of Approval

(1) ERCOT may revoke in full or in part any approval of Metering Facilities, including a provisional approval if:

(a) ERCOT or a TSP or DSP EPS Meter Inspector demonstrates that all or part of the EPS Metering Facilities covered by that approval no longer meet the approval criteria for EPS Metering Facilities contained in this Section and the SMOG; and

(b) ERCOT has given written Notice to the TSP or DSP stating that the identified EPS Metering Facilities do not meet the approval criteria and the reasons and that the TSP or DSP fails to correct the deficiency and satisfy ERCOT, within 30 days, that the EPS Metering Facilities meet the approval criteria.

(2) If ERCOT revokes in full or part an approval of EPS Metering Facilities, the TSP or DSP may seek re-approval of the EPS Metering Facilities by requesting approval in accordance with this Section.

10.4.3.5 Changes to Approved EPS Metering Facilities

(1) Each TSP and DSP shall notify ERCOT of any planned modifications or changes to be made to any EPS Metering Facilities that would affect the EPS Metering Facility's approval, not less than ten Business Days prior to the intended implementation of the change. Before the intended date of the change, ERCOT may request additional information from the TSP or DSP to demonstrate that the EPS Metering Facilities will still meet the applicable approval standards; the TSP or DSP shall promptly comply with such request for information. ERCOT may at its discretion audit Metering Facilities to determine compliance. The TSP or DSP shall provide ERCOT with meter specific program details, as downloaded from the meter, when the EPS Meter is programmed.

10.4.3.6 Confirmation of Certification

(1) On the written request of ERCOT, the TSP or DSP shall provide ERCOT written or electronic confirmation that the Metering Facilities of each metered Entity that the TSP or DSP represents have been certified in accordance with this Section and the SMOG within five Business Days of receiving such a request from ERCOT.

10.5 TSP and DSP EPS Meter Inspectors

10.5.1 List of TSP and DSP EPS Meter Inspectors

(1) ERCOT shall maintain a list of TSP and DSP ERCOT-Polled Settlement (EPS) Meter Inspectors, and details related to ERCOT training to become a Transmission Service Provider (TSP) or Distribution Service Provider (DSP) EPS Meter Inspector.

10.5.2 EPS Meter Inspector Approval Process

10.5.2.1 TSP and DSP Responsibilities

(1) Each TSP and DSP shall ensure that personnel performing EPS Meter Facility certification duties are approved EPS Meter Inspectors and comply with this Section and the Settlement Metering Operating Guide (SMOG). A TSP or DSP EPS Meter Inspector is required to complete an ERCOT EPS Meter Inspector training session.

(2) The TSP and DSP shall submit to ERCOT the following information for individuals performing EPS Metering Facility certification.

(a) Name of individual;

(b) Time period the individual has been testing Generation Resource or transmission interconnect metering points;

(c) TSP or DSP statement indicating that the individual has the technical expertise to perform EPS Metering Facility certification; and,

(d) Additional documentation as required by ERCOT.

10.5.2.2 ERCOT Responsibilities

(1) ERCOT shall hold EPS Meter Inspector training sessions on a regularly scheduled basis. Sessions must include information on the following:

(a) Market responsibilities of EPS Meter Inspectors;

(b) Documentation requirements for the site certification;

(c) Overview of EPS Metering Facilities related topics and documents;

(d) Protocols requirements;

(e) SMOG requirements; and

(f) Technical requirements.

(2) ERCOT shall issue a certificate of attendance to individuals upon completion of the EPS Meter Inspector training sessions.

(3) ERCOT shall have the authority to revoke an individual's involvement with EPS Metering Facility certification.

10.6 Auditing and Testing of Metering Facilities

10.6.1 EPS Meter Entities

10.6.1.1 ERCOT Requirement for Audits and Tests

(1) ERCOT shall have the right to audit any ERCOT-Polled Settlement (EPS) Metering Facility that it considers necessary or to request and witness a test carried out by a Transmission Service Provider (TSP) or Distribution Service Provider (DSP) EPS Meter Inspector.

10.6.1.2 TSP and DSP Testing Requirements for EPS Metering Facilities

(1) At a minimum, the TSP and DSP EPS Meter Inspector shall conduct testing of EPS Meters on an annual basis, within the same month of each year as the previous year's test. Metering Facilities used in the ERCOT system for settlement must be tested pursuant to the TSP or DSP tariffs, the Settlement Metering Operating Guide and these Protocols.

(2) Instrument transformers used in settlement metering circuits must be tested per the American National Standards Institute (ANSI) C12.1, Code for Electricity Metering, and the following guidelines:

(a) Magnetic Instrument Transformers do not require periodic testing;

(b) Coupling Capacitor Voltage Transformers (CCVTs) shall be tested for accuracy:

(i) By the end of the year in which the fifth anniversary of the previous test occurs; or

(ii) By the end of the year in which the sixth anniversary of the previous test occurs, if the previous test occurred during the fourth quarter of the year.

(3) ERCOT may determine that periodic testing of CCVTs is not required once these devices have been proven to be stable. If the devices have shown themselves to be unstable, ERCOT may discontinue the use of these devices for settlement purposes.

10.6.1.3 Failure to Comply

(1) If an EPS Metering Facility fails to comply with ERCOT's audit or test procedures, ERCOT shall issue a warning to the TSP or DSP responsible for such Metering Facilities. If the TSP or DSP fails to comply with ERCOT's recommendations in a reasonable time, as determined by ERCOT, ERCOT shall notify the Public Utility Commission of Texas (PUCT) or the appropriate Governmental Authority.

10.6.1.4 Requests by Market Participants

(1) Market Participants shall follow appropriate Governmental Authority rules for requesting the testing of Metering Facilities.

10.6.2 TSP and DSP Metered Entities

10.6.2.1 Requirement for Audit and Testing

(1) Audit and Testing by a TSP or DSP

Each TSP or DSP shall conduct (or engage a qualified Entity to conduct) audits and tests of the Metering Facilities of the TSP or DSP Metered Entities that it represents to ensure compliance with all applicable requirements of any relevant Governmental Authority. Each TSP and DSP shall undertake any other actions that are reasonably necessary to ensure the accuracy and integrity of the meter data.

(2) Audit and Testing Requests by an affected Market Participant

Subject to any applicable Governmental Authority requirements, an affected Market Participant shall have the right to witness an audit or test carried out by the TSP or DSP or its authorized representative.

10.6.2.2 TSP and DSP Requirement to Certify per Governmental Authorities

(1) If a Governmental Authority has authority to certify meter installations, then the TSP or DSP shall comply with such regulations.

10.7 ERCOT Request for Installation of EPS Metering Facilities

10.7.1 Additional EPS Metering Installations

(1) If ERCOT determines that there is a potential need to install additional ERCOT-Polled Settlement (EPS) Metering Facilities on the ERCOT System, ERCOT shall notify the relevant Transmission Service Provider (TSP) or Distribution Service Provider (DSP) in writing or electronically. ERCOT's Notice must include the following information:

(a) The location of the meter point at which the additional EPS Metering Facilities are required;

(b) The projected installation date by which the relevant EPS Metering Facilities should be installed;

(c) The reason for the need to install the additional EPS Metering Facilities; and

(d) Any other information that ERCOT considers relevant.

(2) A TSP or DSP that is notified by ERCOT of the potential need to install additional EPS Metering Facilities must:

(a) Give ERCOT written confirmation of receipt of Notice within three Business Days of receiving such Notice;

(b) Submit an EPS Design Proposal to ERCOT within 45 Business Days of receiving such Notice.

(3) The TSP or DSP may request a waiver to install additional Metering Facilities.

10.7.2 Approval or Rejection of Waiver Request for Installation of EPS Metering Facilities

(1) ERCOT may approve, or reject a waiver request at ERCOT's sole discretion.

10.7.2.1 Approval

(1) If ERCOT approves a waiver request, then ERCOT shall promptly notify the TSP or DSP.

10.7.2.2 Rejection

(1) If ERCOT rejects a waiver request, then ERCOT shall promptly notify the TSP or DSP and shall set forth the reasons for its rejection. The TSP or DSP may submit to ERCOT a revised waiver request within 14 Business Days of receiving such Notice. If ERCOT

rejects for a second time a waiver request submitted by a TSP or DSP with respect to the same or similar Notice issued by ERCOT as described above, then ERCOT and the TSP or DSP shall use good faith efforts to reach agreement on the requirements and disputed items. In the absence of agreement either Entity may refer the dispute to the ADR Procedures as described in Section 20, Alternative Dispute Resolution Procedure.

10.8 Maintenance of Metering Facilities

10.8.1 EPS Meters

10.8.1.1 Duty to Maintain EPS Metering Facilities

(1) Each Transmission Service Provider (TSP) and Distribution Service Provider (DSP) shall maintain its ERCOT-Polled Settlement (EPS) Metering Facilities to meet the standards prescribed by this Section and the Settlement Metering Operating Guide (SMOG). If the EPS Metering Facilities of a TSP or DSP require maintenance to ensure that they operate in accordance with the requirements of this Section, SMOG, or any Governmental Authority, then the TSP or DSP shall notify ERCOT of the need for such maintenance. The TSP or DSP shall also inform ERCOT five Business Days in advance of the time period during which such maintenance is expected to occur. During that period, the TSP or DSP, or its authorized representative, after notifying ERCOT, shall be entitled to access sealed EPS Metering Facilities to which access is required in order to undertake the required maintenance.

10.8.1.2 EPS Metering Facilities Repairs

(1) If an EPS Metering Facility requires repairs to ensure that it operates in accordance with the requirements of this Section, then the TSP or DSP shall immediately notify ERCOT of the need for repairing such Metering Facility. If, however, operating conditions are such that it is not possible for the Transmission and/or Distribution Service Provider (TDSP) to notify ERCOT of the need for repairs, then the TDSP may make the necessary repairs and then notify ERCOT of the repairs prior to the end of the next Business Day.

(a) Where no Back-up Meter exists or Back-up Meter data is unavailable, the TSP or DSP shall ensure that the metering point is repaired and operational within 12 hours of problem detection. ERCOT may, at its discretion, reduce the repair timeline from 12 to six hours if the meter data is required for Real-Time Market (RTM) Settlements on the same day or an upcoming ERCOT non-Business Day.

(b) Where a functional and operational Back-up Meter exists, the TSP or DSP shall ensure that the metering point is repaired and operational within five Business Days of problem detection.

10.8.2 TSP or DSP Metered Entities

(1) Each TSP and DSP shall maintain its Metering Facilities in accordance with the requirements of the relevant Governmental Authorities and according to this Section.

10.9 Standards for Metering Facilities

(1) For Transmission Service Provider (TSP) and Distribution Service Provider (DSP) Metered Entities, an Interval Data Recorder (IDR) Meter is required on any of the following locations/sites:

(a) Non-Opt-In Entity (NOIE) or External Load Serving Entity (ELSE) metering points used to determine the total Load for that NOIE or ELSE; and

(b) Block Load Transfer (BLT) metering points, registered for Settlements in accordance with Section 6.5.9.5.1, Registration and Posting of BLT Points.

(2) For TSP and DSP Metered Entities, an IDR is required on any of the following locations/sites:

(a) Load Resources participating in the Ancillary Services markets, with the exception of Aggregate Load Resources (ALRs) for which statistical sampling is used to validate telemetry, as detailed in the document titled "Requirements for Aggregate Load Resource Participation in the ERCOT Markets";

(b) Settlement Only Distribution Generators (SODGs); and

(c) Locations meeting IDR requirements defined in Section 18, Load Profiling.

10.9.1 ERCOT-Polled Settlement Meters

(1) The TSP or DSP for ERCOT-Polled Settlement (EPS) Meters shall ensure that the EPS Metering Facilities comply with this Section and the Settlement Metering Operating Guide (SMOG). This requirement does not apply to Resource Entity-owned Metering Facilities used to measure, calculate, or telemeter Energy Storage Resource (ESR) auxiliary Load pursuant to Section 10.2.4, Resource Entity Calculation and Telemetry of ESR Auxiliary Load Values.

[NPRR995: Replace paragraph (1) above with the following upon system implementation:]

(1) The TSP or DSP for ERCOT-Polled Settlement (EPS) Meters shall ensure that the EPS Metering Facilities comply with this Section and the Settlement Metering Operating Guide (SMOG). This requirement does not apply to Resource Entity-owned Metering Facilities used to measure, calculate, or telemeter Energy Storage Resource (ESR), Settlement Only Distribution Energy Storage System (SODESS), or Settlement Only Transmission Energy

Storage System (SOTESS) auxiliary Load pursuant to Section 10.2.4, Resource Entity Calculation and Telemetry of ESR, SODESS, or SOTESS Auxiliary Load Values.

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

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

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

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

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

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

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

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

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

XX:15:00
XX:30:00
XX:45:00
XX:00:00

10.9.2 TSP or DSP Metered Entities

(1) IDRs used for settlement of TSP or DSP Metered Entities shall:

(a) Capture energy consumption in increments consistent with, or in fractions of, ERCOT-defined settlement time interval;

(b) Provide interval data on a schedule that supports the requirements of final Settlement;

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

(d) Have time synchronization capability;

(e) Maintain meter clocks on a time reference that enables the TSP or DSP to submit data on the CPT. The meter clock shall be synchronized to within at least +/- 5% of the Settlement Interval when compared to the NIST Atomic Clock;

(f) Have data aggregated to the appropriate Settlement Interval time block by the TSP or DSP prior to the data being sent to ERCOT if recorded at increments less than the ERCOT defined Settlement Interval;

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

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

XX:15:00
XX:30:00
XX:45:00
XX:00:00

(i) IDR data submitted to ERCOT for Operating Days January 1, 2003, or later must contain only whole days with start times beginning at 0000 and stop times ending at 2359.

10.9.3 Failure to Comply with Standards

(1) If the TSP or DSP fails to comply with the standards for EPS Metering Facilities referred to in this Section and the SMOG, then ERCOT shall notify the Public Utility Commission of Texas (PUCT) or the appropriate Governmental Authority.

10.10 Security of Meter Data

10.10.1 EPS Meters

(1) A Transmission Service Provider (TSP) or Distribution Service Provider (DSP) is responsible for data security of the ERCOT-Polled Settlement (EPS) Metering Facilities on their system. This responsibility extends to third-party contracts and access to EPS Metering Facilities.

(2) A TSP, DSP or any Entity authorized to poll EPS Meters may not issue any EPS Meter programming passwords to any Market Participant.

10.10.1.1 TSP and DSP Data Security Responsibilities

(1) Each TSP and DSP shall:

(a) Maintain and modify the passwords for programming and read access to EPS Meters;

(b) Provide the appropriate password access to ERCOT, which will allow ERCOT to synchronize the meter clock;

(c) Establish any other security requirements for accessing the EPS Meters so as to ensure the security of those meters and their meter data;

(d) Coordinate any EPS Meter programming parameter changes with ERCOT according to this Section, including informing the Load or Resource Entity of any changes to the meter;

(e) Upon request of the Resource Entity that represents an EPS metered facility, provide the EPS meter "read only" password to such Resource Entity for such facility and other EPS metered facility required to calculate their Qualified Scheduling Entity (QSE) Load, to the extent that such provision does not violate the Customer service and protection provisions of the Public Utility Commission of Texas (PUCT) Substantive Rules; and

(f) Modify the "read only" password for EPS meters when a Resource Entity that represents a facility requests a change due to data security reasons, provided that such modification does not violate the Customer service and protection provisions of the PUCT Substantive Rules.

10.10.1.2 ERCOT Data Security Responsibilities

(1) ERCOT may request that TSP or DSP alter the password and other requirements for accessing EPS Meters, as it deems necessary.

10.10.1.3 Resource Entity Data Security Responsibilities

(1) A Resource Entity must request that the TSP or DSP modify the EPS Meter "read only" password for a facility when the Resource Entity relationships that affect EPS Meter data security change. Such request must include the reason for the request.

10.10.1.4 Third Party Access Withdrawn

(1) If, in the reasonable opinion of ERCOT, access granted to a third party interferes with or impedes ERCOT's ability to poll any EPS Meter, ERCOT may require immediate withdrawal of any access granted to such third party. Separate access through additional

communications ports may be allowed so long as it does not interfere with ERCOT's ability to communicate with the meter.

10.10.1.5 Meter Site Security

(1) EPS Metering Facilities and secondary devices that could have any impact on the performance of the EPS Metering Facilities must be sealed to the extent practicable.

(2) ERCOT shall provide each TSP and DSP with uniquely numbered seals to be used by the TSP or DSP EPS Meter Inspector to seal EPS Meters and EPS Meter test switches. Procedures for seal use shall be in accordance with this Section and the SMOG.

10.10.2 TSP or DSP Metered Entities

(1) Security for TSP and DSP polled meters and meter data shall be the responsibility of the TSP or DSP. Each TSP and DSP shall maintain polled meters in accordance with applicable Governmental Authority rules and regulations. The TSP and DSP shall ensure that only Customer-approved Market Participants have access to the Customer meter.

10.11 Validating, Editing, and Estimating of Meter Data

10.11.1 EPS Meters

(1) The raw meter data that ERCOT retrieves from ERCOT-Polled Settlement (EPS) Meters must be processed by Meter Data Acquisition System (MDAS) using the Validating, Editing, and Estimating (VEE) procedures published in Section 11, Data Acquisition and Aggregation, and the Settlement Metering Operating Guide (SMOG) in order to produce Settlement Quality Meter Data. During periods for which no primary EPS Meter data is available, ERCOT shall use the backup meter data or substitute estimated usage data for that metered Entity using estimation procedures referred to in these Protocols and the SMOG. This data shall be used by ERCOT in its settlement and billing process.

10.11.2 Obligation to Assist

(1) At the request of ERCOT, a Transmission Service Provider (TSP), Distribution Service Provider (DSP) and Market Participant shall promptly assist ERCOT in correcting or replacing defective data from EPS Meters and in detecting and correcting underlying causes for such defects. Such assistance shall be rendered in a timely manner so that the settlement process is not delayed.

10.11.3 TSP or DSP Settlement Meters

(1) The TSP and DSP shall provide ERCOT with Settlement Quality Meter Data for the TSP or DSP Settlement Meters on its system and shall ensure that at a minimum the Validation, Editing and Estimating (VEE) requirements as specified in the Uniform Business Practices (UBP) standard for VEE have been properly performed on such data. ERCOT shall not perform any VEE on the Settlement Quality Meter Data it receives from TSP or DSP.

(2) The following UBP manual validation processes are exempt for Interval Data:

(a) Spike Check; and

(b) Reactive channel check for kWh data.

10.12 Communications

10.12.1 ERCOT Acquisition of ERCOT-Polled Settlement (EPS) Meter Data

(1) ERCOT shall acquire ERCOT-Polled Settlement (EPS) Meter data via the following communication links:

(a) ERCOT private communication network established by ERCOT for ERCOT Real-Time metered Entities; or

(b) Other ERCOT-approved communication technology provided by the Transmission Service Provider (TSP) or Distribution Service Provider (DSP).

10.12.2 TSP or DSP Meter Data Submittal to ERCOT

(1) TSP and DSPs shall submit meter consumption data to ERCOT through a standard data interface into the Meter Data Acquisition System (MDAS). In order to submit meter consumption data, a TSP or DSP shall use an automated system with an ERCOT-approved and tested interface to MDAS.

10.12.3 ERCOT Distribution of Settlement Quality Meter Data

(1) ERCOT shall distribute Settlement Quality Meter Data to Market Participants:

(a) Whenever a TSP or DSP submits meter consumption data to ERCOT via a Texas Standard Electronic Transaction (TX SET), ERCOT will forward the consumption data and other information for the Electric Service Identifiers (ESI IDs) to the Competitive Retailer (CR) indicated in the transaction. ERCOT relies upon the TSP or DSP to ensure that the CR included in the transaction is the appropriate CR for the meter data timeframe. ERCOT does not further validate the accuracy of the CR indicated.

(b) Whenever a TSP or DSP submits meter data to ERCOT via an ERCOT specified file format for Advanced Meters, upon certified request by a Market Participant, ERCOT shall make that data available to the Market Participant via Market Information System (MIS) Certified Area.

(c) On Request – A Market Participant may submit an electronic request via the MIS Certified Area for specific meter consumption data. ERCOT will receive and validate the request and, if appropriate, automatically forward the appropriate information to the Market Participant.

10.13 Meter Identification

(1) The device id used to identify an ERCOT-Polled Settlement (EPS) Meter shall be unique for such meters on the ERCOT System. ERCOT shall maintain a master list of device ids and shall notify each Transmission Service Provider (TSP) and Distribution Service Provider (DSP) if the device id selected has been used elsewhere in Meter Data Acquisition System (MDAS).

10.14 Exemptions from Compliance to Metering Protocols

10.14.1 Authority to Grant Exemptions

(1) ERCOT may grant on a case by case basis, exemptions from compliance on a temporary basis until new arrangements can be completed in accordance with the guidelines as listed below. Any permanent exemption to this Section requires approval by the Technical Advisory Committee (TAC) and the ERCOT Board. Any permanent exemption shall be subject to periodic review and revocation by the ERCOT Board.

10.14.2 Guidelines for Granting Temporary Exemptions

(1) ERCOT shall use the following process when considering applications for temporary exemptions from compliance with this Section and the Settlement Metering Operating Guide (SMOG).

(a) Publication of Guidelines: ERCOT shall post on the ERCOT website the general guidelines that it will use when considering applications for exemptions within five Business Days of a change of guidelines, so as to achieve consistency in its reasoning and decision-making and to give prospective applicants an indication of whether an application for exemption may be considered favorably.

(b) Publication of Decision: ERCOT shall post on the ERCOT website the application for exemption and whether the application was approved or rejected by ERCOT and the reasons for rejecting the application, if applicable, on a quarterly basis.

10.14.3 Procedure for Applying for Exemptions

(1) All applications to ERCOT for exemptions from compliance with the requirements of this Section must be submitted in writing. ERCOT shall confirm receipt of an application within three Business Days of receipt. For temporary exemptions, ERCOT shall decide whether to grant or reject the exemption within 45 Business Days of receipt. For permanent exemptions, ERCOT shall forward the application to TAC for review at the next scheduled meeting for which appropriate Notice can be made. At any time during the application process, ERCOT may require the applicant to provide additional information in support of its application.

(2) The applicant shall provide such additional information to ERCOT within five Business Days of receiving the request or within such other period as ERCOT may specify. If ERCOT requests additional information more than 40 Business Days after the date on which it received the application, ERCOT shall have an additional seven Business Days after receiving that additional information in which to consider the application. If the applicant does not provide the additional information requested, then ERCOT shall reject the application, in which case it will notify the applicant that its application has been rejected for failure to provide the additional information.

10.14.3.1 Information to be Included in the Application

(1) The application for exemption to ERCOT shall include:

(a) A detailed description of the exemption sought. including specific reference to the relevant Section(s) of these Protocols or the SMOG authorizing ERCOT to grant the exemption, and the Metering Facilities to which the exemption will apply;

(b) A detailed statement of the reason for seeking the exemption, including any supporting documentation;

(c) Details of the Entity(s) to which the exemption will apply;

(d) Details of the location to which the exemption will apply;

(e) Details of the period of time for which the exemption will apply, including the proposed start and finish dates of that period; and

(f) Any other information requested by ERCOT.

ERCOT Nodal Protocols

Section 3: Management Activities for the ERCOT System

April 1, 2023

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3 MANAGEMENT ACTIVITIES FOR THE ERCOT SYSTEM

(1) This section focuses on the management activities, including Outage Coordination, Resource Adequacy, Load forecasting, transmission operations and planning, and contracts for Ancillary Services for the ERCOT System.

3.1 Outage Coordination

(1) "Outage Coordination" is the management of Transmission Facilities Outages and Resource Outages in the ERCOT System. Facility owners are solely and directly responsible for the performance of all maintenance, repair, and construction work, whether on energized or de-energized facilities, including all activities related to providing a safe working environment.

3.1.1 Role of ERCOT

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(l) Establishing and implementing communication procedures:

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

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

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

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

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

(n) Planning and analyzing Transmission Facilities Outages.

3.1.2 Planned Outage, Maintenance Outage, or Rescheduled Outage Data Reporting

(1) Each Resource Entity shall use reasonable efforts, consistent with Good Utility Practice, to continually update its Outage plans for all Outages. All information submitted about Planned Outages, Maintenance Outages, or Rescheduled Outages must be submitted by the Resource Entity or the TSP under this Section. If an Outage plan for a Resource is also applicable to the Current Operating Plan (COP), the Qualified Scheduling Entity (QSE) responsible for the Resource shall also update the COP to provide the same information describing the Outage. Each TSP shall use reasonable efforts, consistent with Good Utility Practice, to continually update its Outage plan, including, but not limited to, submitting the actual start and end date and time for Planned Outages of Transmission Facilities in the Outage Scheduler by hour ending 0800 of the current Operating Day for all scheduled work completed prior to hour ending 0600 of the current Operating Day.

[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) Each Resource Entity shall use reasonable efforts, consistent with Good Utility Practice, to continually update its Outage plans for all Outages. All information submitted about Planned Outages, Maintenance Outages, or Rescheduled Outages must be submitted by the Resource Entity, TSP, or DCTO under this Section. If an Outage plan for a Resource is also applicable to the Current Operating Plan (COP), the Qualified Scheduling Entity (QSE) responsible for the Resource shall also update the COP to provide the same information describing the Outage. Each TSP and DCTO shall use reasonable efforts, consistent with Good Utility Practice, to continually update its Outage plan, including, but not limited to, submitting the actual start and end date and time for Planned Outages of Transmission Facilities in the Outage Scheduler by hour ending 0800 of the current Operating Day for all scheduled work completed prior to hour ending 0600 of the current Operating Day.

3.1.3 Rolling 12-Month Outage Planning and Update

3.1.3.1 Transmission Facilities

(1) Each TSP shall provide to ERCOT a plan for Planned Outages, Maintenance Outages and Rescheduled Outages in an ERCOT-provided format for the next 12 months updated monthly. Planned Outage, Maintenance Outage, and Rescheduled Outage scheduling data for Transmission Facilities must be kept current. Updates must identify all changes to any previously proposed Planned Outages, Maintenance Outages, or Rescheduled Outages and any additional Planned Outages, Maintenance Outages, or Rescheduled Outages anticipated over the next 12 months. ERCOT shall coordinate in-depth reviews of the 12-month plan with each TSP at least twice per year.

[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) Each TSP and DCTO shall provide to ERCOT a plan for Planned Outages, Maintenance Outages, and Rescheduled Outages in an ERCOT-provided format for the next 12 months updated monthly. Planned Outage, Maintenance Outage, and Rescheduled Outage scheduling data for Transmission Facilities must be kept current. Updates must identify all changes to any previously proposed Planned Outages, Maintenance Outages, or Rescheduled Outages and any additional Planned Outages, Maintenance Outages, or Rescheduled Outages anticipated over the next 12 months. ERCOT shall coordinate in-depth reviews of the 12-month plan with each TSP at least twice per year.

3.1.3.2 Resources

(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.

3.1.4 Communications Regarding Resource and Transmission Facilities Outages

3.1.4.1 Single Point of Contact

(1) All communications concerning a Planned Outage, Maintenance Outage, or Rescheduled Outage must be between ERCOT and the designated "Single Point of Contact" for each TSP or Resource Entity. All nonverbal communications concerning Planned Outages or Rescheduled Outages must be conveyed through an electronic interface as specified by ERCOT. The TSP or Resource Entity shall identify, in its initial request or response, the Single Point of Contact, with primary and alternate means of communication. The Resource Entity or TSP shall submit a Notice of Change of Information (NCI) form (Section 23, Form E, Notice of Change of Information) when changes occur to a Single Point of Contact. This identification must be confirmed in all communications with ERCOT regarding Planned Outage, Maintenance Outage, or Rescheduled Outage requests.

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

(1) All communications concerning a Planned Outage, Maintenance Outage, or Rescheduled Outage must be between ERCOT and the designated "Single Point of Contact" for each TSP, DCTO, or Resource Entity. All nonverbal communications concerning Planned Outages or Rescheduled Outages must be conveyed through an electronic interface as specified by ERCOT. The TSP, DCTO, or Resource Entity shall identify, in its initial request or response, the Single Point of Contact, with primary and alternate means of communication. The Resource Entity, TSP, or DCTO shall submit a Notice of Change of Information (NCI) form (Section 23, Form E, Notice of Change of Information) when changes occur to a Single Point of Contact. This identification must be confirmed in all communications with ERCOT regarding Planned Outage, Maintenance Outage, or Rescheduled Outage requests.

(2) The Single Point of Contact must be either a person or a position available seven days per week and 24 hours per day for each Resource Entity and TSP. The Resource Entity shall designate its QSE as its Single Point of Contact. The designated Single Point of Contact for a Generation Resource that has been split into two or more Split Generation Resources shall be the Master QSE. The Single Point of Contact for the TSP must be designated under the ERCOT Operating Guides.

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

(2) The Single Point of Contact must be either a person or a position available seven days per week and 24 hours per day for each Resource Entity, TSP, or DCTO. The Resource Entity shall designate its QSE as its Single Point of Contact. The designated Single Point of Contact for a Generation Resource that has been split into two or more Split Generation Resources shall be the Master QSE. The Single Point of Contact for each TSP and DCTO must be designated under the ERCOT Operating Guides.

3.1.4.2 Method of Communication

(1) ERCOT, each TSP, and each Resource Entity shall communicate according to ERCOT procedures under these Protocols. All submissions, changes, approvals, rejections, and withdrawals regarding Outages must be processed through the ERCOT Outage Scheduler on the ERCOT programmatic interface, except for Forced Outages and Maintenance Level I Outages, which must be communicated to ERCOT immediately via the Current Operating Plan if submitted for a Resource and using the Outage Scheduler if submitted by a TSP. This does not prohibit any verbal communication when the situation warrants it. ERCOT shall develop guidelines for the types of events that may require verbal communication.

[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 and each TSP, DCTO, and Resource Entity shall communicate according to ERCOT procedures under these Protocols. All submissions, changes, approvals, rejections, and withdrawals regarding Outages must be processed through the ERCOT Outage Scheduler on the ERCOT programmatic interface, except for Forced Outages and Maintenance Level I Outages, which must be communicated to ERCOT immediately via the Current Operating Plan if submitted for a Resource and using the Outage Scheduler if submitted by a TSP or DCTO. This does not prohibit any verbal

communication when the situation warrants it. ERCOT shall develop guidelines for the types of events that may require verbal communication.

3.1.4.3 Reporting for Planned Outages, Maintenance Outages, and Rescheduled Outages of Resource and Transmission Facilities

(1) Each Resource Entity and TSP shall submit information regarding proposed Planned Outages, Maintenance Outages, and Rescheduled Outages of Transmission Facilities or Planned Outages and Maintenance Outages of Generation Resources under procedures adopted by ERCOT. The obligation to submit that information applies to each Resource Entity that is responsible to operate or maintain a Generation Resource that is part of or that affects the ERCOT System. The obligation to submit that information applies to each TSP or Resource Entity that is responsible to operate or maintain Transmission Facilities that are part of or affect the ERCOT System. A Resource Entity or TSP is also obligated to submit information for Transmission Facilities or Generation Resources that are not part of the ERCOT System or that do not affect the ERCOT System if that information is required for regional security coordination as determined by ERCOT.

[NPRR857 and NPRR1014: Replace applicable portions of 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 for NPRR857; and upon system implementation for NPRR1014:]

(1) Each Resource Entity, TSP, and DCTO shall submit information regarding proposed Planned Outages, Maintenance Outages, and Rescheduled Outages of Transmission Facilities or Planned Outages and Maintenance Outages of Generation Resources or Energy Storage Resources (ESRs) under procedures adopted by ERCOT. The obligation to submit that information applies to each Resource Entity that is responsible to operate or maintain a Generation Resource or ESR that is part of or that affects the ERCOT System. The obligation to submit that information applies to each TSP, DCTO, or Resource Entity that is responsible to operate or maintain Transmission Facilities that are part of or affect the ERCOT System. A Resource Entity, TSP, or DCTO is also obligated to submit information for Transmission Facilities or Generation Resources or ESRs that are not part of the ERCOT System or that do not affect the ERCOT System if that information is required for regional security coordination as determined by ERCOT.

(2) Before taking an RMR or Black Start Resource (“Reliability Resources”) out of service for a Planned Outage or Maintenance Outage, the Single Point of Contact for that Reliability Resource must obtain ERCOT’s approval of the schedule of the Planned Outage or Maintenance Outage. ERCOT shall review and approve or reject each

proposed Planned Outage or Maintenance Outage Schedule under this Section and the applicable Agreements.

(3) A Firm Fuel Supply Service Resource (FFSSR) shall not schedule or request a Planned Outage that would occur during the period of December 1 through March 1.

3.1.4.4 Management of Forced Outages or Maintenance Outages

(1) In the event of a Forced Outage, the Resource Entity or QSE, as appropriate, or TSP must notify ERCOT as soon as practicable by:

[NPRR857 and NPRR1085: Replace applicable portions of 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 for NPRR857; or upon system implementation for NPRR1085:]

(1) In the event of a Forced Outage, after the affected equipment is removed from service, the Resource Entity or QSE, as appropriate, TSP, or DCTO must notify ERCOT of its action by:

(a) For Resource Outages:

(i) Changing the telemetered Resource Status, including a text description when it becomes known, of the cause of the Forced Outage;

(ii) Updating the COP; and

(iii) Updating the Outage Scheduler.

[NPRR1085: Replace paragraph (a) above with the following upon system implementation:]

(a) For Resource Outages:

(i) Changing the telemetered Resource Status to the appropriate Off-Line status as soon as practicable but no longer than 15 minutes after the Forced Outage occurs;

(ii) Updating the COP as soon as practicable but no longer than 60 minutes after the Forced Outage occurs; and

(iii) Updating the Outage Scheduler, if necessary.

(b) For Transmission Facilities Forced Outages:

(i) Changing the telemetered status of the affected Transmission Elements; and

(ii) Updating the Outage Scheduler with the expected return-to-service time.

[NPRR1085: Insert paragraph (c) below upon system implementation:]

(c) Each TSP and QSE shall timely update telemetry, COP status, and/or the Outage Scheduler, as applicable, in accordance with paragraphs (a) and (b) above unless in the reasonable judgment of the TSP or QSE, such compliance would create an undue threat to safety, undue risk of bodily harm, or undue damage to equipment. The TSP or QSE is excused from updating the telemetered status, COP, and/or Outage Scheduler only for so long as the undue threat to safety, undue risk of bodily harm, or undue damage to equipment exists. The time for updating the telemetered status, COP, and/or Outage Scheduler begins once the undue threat to safety, undue risk of bodily harm, or undue damage to equipment no longer exists.

(2) Forced Outages may require ERCOT to review and withdraw approval of previously approved or accepted, as applicable, Planned Outage, Maintenance Outage, or Rescheduled Outage schedules to ensure reliability.

(3) For Maintenance Outages, the Resource Entity or QSE, as appropriate, or TSP shall notify ERCOT of any Resource or Transmission Facilities Maintenance Outage according to the Maintenance Outage Levels by updating the COP and Outage Scheduler. ERCOT shall coordinate the removal of facilities from service within the defined timeframes as specified by the TSP, QSE or Resource Entity in its notice to ERCOT.

[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) For Maintenance Outages, the Resource Entity or QSE, as appropriate, TSP, or DCTO shall notify ERCOT of any Resource or Transmission Facilities Maintenance Outage according to the Maintenance Outage Levels by updating the COP and Outage Scheduler. ERCOT shall coordinate the removal of facilities from service within the defined timeframes as specified by the TSP, DCTO, QSE, or Resource Entity in its notice to ERCOT.

(4) ERCOT may require supporting information describing Forced Outages and Maintenance Outages. ERCOT may reconsider and withdraw approvals of other previously approved Transmission Facilities Outage or an Outage of a Reliability Resource as a result of Forced Outages or Maintenance Outages, if necessary, in ERCOT's determination to protect system reliability. When ERCOT approves a Maintenance Outage, ERCOT shall coordinate timing of the appropriate course of action under these Protocols.

(5) Removal of a Resource or Transmission Facilities from service under Maintenance Outages must be coordinated with ERCOT. To minimize harmful impacts to the system in urgent situations, the equipment may be removed immediately from service, provided notice is given immediately, by the Resource Entity or TSP, to ERCOT of such action.

[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) Removal of a Resource or Transmission Facilities from service under Maintenance Outages must be coordinated with ERCOT. To minimize harmful impacts to the system in urgent situations, the equipment may be removed immediately from service, provided the Resource Entity, TSP, or DCTO immediately gives notice of such action to ERCOT.

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

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

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

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

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

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

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

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

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

3.1.4.6 Outage Coordination of Potential Transmission Emergency Conditions

(1) If ERCOT forecasts an inability to meet applicable transmission reliability standards, has exercised all other reasonable options, and there is only one QSE with approved or accepted Resource Outages which could resolve the situation if the start of one or more of the Resource Outages at a single Resource site were delayed or one or more ongoing Resource Outages at a single Resource site were restored early, then ERCOT may contact that QSE and attempt to reach a mutually acceptable solution to delay or reschedule one or more of those Outages. In this case, ERCOT is not obligated to follow the process described in Section 3.1.6.9, Withdrawal of Approval and Rescheduling of Approved Planned Outages of Resource Facilities. ERCOT shall not provide information to the QSE during these contacts which is not directly related to the QSE's Planned Resource Outage(s) and is not otherwise available to all other Market Participants.

(2) If ERCOT and the QSE are unable to reach a mutually agreeable solution to change the Resource Outage, ERCOT may issue an Outage Schedule Adjustment (OSA) to the QSE for the Resource.

[NPRR930: Insert paragraph (3) below upon system implementation and renumber accordingly:]

(3) If there are Resources at multiple sites with approved or accepted Resource Outages, whose approval or acceptance could be withdrawn to meet the applicable transmission reliability standards, ERCOT shall utilize the process described in Section 3.1.6.9.

(3) This Section is not intended to restrict ongoing Outage Coordination activities occurring more than seven days in advance of Real-Time.

3.1.4.7 Reporting of Forced Derates

(1) If a Generation Resource experiences a Forced Derate in an amount greater than ten MW, and 5% of its Seasonal net maximum sustainable rating, and the Forced Derate lasts longer than 30 minutes, the Resource Entity or its designee must enter the Forced Derate into the Outage Scheduler as soon as practicable but no longer than 60 minutes after the beginning of the Forced Derate.

(2) If a Forced Derate that has already been reported changes by an amount greater than ten MW and 5% of the Generation Resource's Seasonal net maximum sustainable rating, and the change lasts longer than 30 minutes, the Resource Entity or its designee must enter the change as a new Forced Derate into the Outage Scheduler as soon as practicable but no longer than 60 minutes after the beginning of the change.

(3) Notwithstanding paragraphs (1) and (2) above, for any Forced Derate or change to a Forced Derate that meets the reporting criteria specified in paragraph (1) or (2) above and that is caused by ambient temperature or humidity, the Resource Entity or its designee must enter the Forced Derate into the Outage Scheduler as soon as practicable but no longer than eight hours after the beginning of the Force Derate or change.

[NPRR1085: Insert paragraphs (4)-(6) below upon system implementation:]

(4) The QSE must appropriately update the telemetered High Sustained Limit (HSL) and any applicable telemetry as specified in paragraph (2) of Section 6.5.5.2, Operational Data Requirements, based on the Forced Derate, as soon as practicable but no longer than 15 minutes after the beginning of a Forced Derate, if the Forced Derate is greater than ten MW and more than 5% of the Seasonal net maximum sustainable rating of the Resource and its expected or actual duration is greater than 30 minutes. Alternatively for a Forced Derate, a QSE may use the ONHOLD process described in paragraph (2) of Section 6.5.5.1, Changes in Resource Status.

(5) The QSE must update the COP as soon as practicable but no longer than 60 minutes after the beginning of a Forced Derate, if the Forced Derate is greater than 20 MW and its expected duration is greater than 120 minutes.

(6) Each QSE shall timely update the telemetered HSL and COP unless in the reasonable judgment of the QSE, such compliance would create an undue threat to safety, undue risk of bodily harm, or undue damage to equipment. The QSE is excused from updating

the telemetered HSL and/or COP only for so long as the undue threat to safety, undue risk of bodily harm, or undue damage to equipment exists. The time for updating the telemetered HSL and/or COP begins once the undue threat to safety, undue risk of bodily harm, or undue damage to equipment no longer exists.

3.1.4.8 Resource Forced Outage Report

(1) Three days after each Operating Day, ERCOT shall post to the ERCOT website a report that identifies each Forced Outage, Maintenance Outage, or Forced Derate of a Generation Resource or Energy Storage Resource (ESR) that occurs during, or that extends into, that Operating Day. At a minimum, the report shall contain:

(a) The Resource name;

(b) The Resource unit code;

(c) The Resource's fuel type;

(d) The type of Outage or derate;

(e) The Resource's applicable Seasonal net maximum sustainable rating;

(f) The available MW during the Outage or derate;

(g) The effective MW reduction due to the Outage or derate;

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

(i) The entry in the "nature of work" field in the Outage Scheduler for each Outage or derate.

3.1.5 Transmission System Outages

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

(1) A TSP or Resource Entity shall request a Planned Outage or Maintenance Outage when any Transmission Facility that is part of the ERCOT Transmission Grid and defined in the Network Operations Model will be removed from its normal service. For Resource Entities within a Private Use Network, this only includes Transmission Facilities at the Point of Interconnection (POI). For TSP requests, the TSPs shall enter such requests in the Outage Scheduler. For Resource Entity requests, the Resource Entity shall enter such requests in the Outage Scheduler. Planned Outages, Maintenance Outages, or Rescheduled Outages for Electrical Buses will be treated as consequentially outaged Transmission Elements. In those cases where a TSP enters the breaker and switch

statuses associated with an Electrical Bus, a downstream topology processor will evaluate the breakers and switches associated with the applicable Electrical Bus to determine if the Electrical Bus is consequentially outaged, and to thereby designate the status of the Electrical Bus. Proposed Transmission Planned Outage or Maintenance Outage information submitted by a TSP or Resource Entity in accordance with this Section constitutes a request for ERCOT's approval of the Outage Schedule associated with the Planned Outage or Maintenance Outage. ERCOT is not deemed to have approved the Outage Schedule associated with the Planned Outage or Maintenance Outage until ERCOT notifies the TSP or Resource Entity of its approval under procedures adopted by ERCOT. ERCOT shall evaluate requests under Section 3.1.5.11, Evaluation of Transmission Facilities Planned Outage or Maintenance Outage Requests.

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

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

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

Approval of Approved Planned Outages, Maintenance Outages, and Rescheduled Outages of Transmission Facilities.

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

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

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

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

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

ERCOT may withdraw approval of the Outage and instruct the TSP to reconnect the Generation Resource if it deems cancellation necessary to address reliability concerns.

3.1.5.2 Receipt of TSP Requests by ERCOT

(1) ERCOT shall acknowledge each request for approval of a Transmission Planned Outage or Maintenance Outage schedule within two Business Hours of the receipt of the request. ERCOT may request additional information or seek clarification from the TSP regarding the information submitted for a proposed Planned Outage or Maintenance Outage for Transmission Facilities.

[NPRR857: Replace Section 3.1.5.2 above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

3.1.5.2 Receipt of TSP and DCTO Requests by ERCOT

(1) ERCOT shall acknowledge each request for approval of a Transmission Planned Outage or Maintenance Outage schedule within two Business Hours of the receipt of the request. ERCOT may request additional information or seek clarification from the TSP or DCTO regarding the information submitted for a proposed Planned Outage or Maintenance Outage for Transmission Facilities.

3.1.5.3 Timelines for Response by ERCOT for TSP Requests

(1) For Transmission Facilities Outages, ERCOT shall approve or reject each request in accordance with the following table:

Amount of time between the request for approval of the proposed Outage and the scheduled start date of the proposed Outage:	ERCOT shall approve or reject no later than:
Three days	1800 hours, two days before the start of the proposed Outage
Between four and eight days	1800 hours, three days before the start of the proposed Outage
Between nine days and 45 days	Four days before the start of the proposed Outage
Between 46 and 90 days	30 days before the start of the proposed Outage
Greater than 90 days	75 days before the start of the proposed Outage

(2) For Outages scheduled at least three days before the scheduled start date of the proposed Outage, ERCOT shall make reasonable attempts to accommodate unusual circumstances that support TSP requests for approval earlier than required by the schedule above.

(3) If circumstances prevent adherence to these timetables, ERCOT shall discuss the request status and reason for the delay of the approval with the requesting TSP and make reasonable attempts to mitigate the effect of the delay on the TSP.

(4) When ERCOT rejects a request for an Outage, ERCOT shall provide the TSP, in written or electronic form, suggested amendments to the schedules of a Planned Outage or Maintenance Outage of Transmission Facilities. Any such suggested amendments accepted by the TSP must be processed by ERCOT as a Planned Outage or Maintenance Outage of Transmission Facilities request under this Section.

[NPRR857: Replace Section 3.1.5.3 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:]

3.1.5.3 Timelines for Response by ERCOT for TSP and DCTO Requests

(1) For Transmission Facilities Outages, ERCOT shall approve or reject each request in accordance with the following table:

Amount of time between the request for approval of the proposed Outage and the scheduled start date of the proposed Outage:	**ERCOT shall approve or reject no later than:**
Three days	1800 hours, two days before the start of the proposed Outage
Between four and eight days	1800 hours, three days before the start of the proposed Outage
Between nine days and 45 days	Four days before the start of the proposed Outage
Between 46 and 90 days	30 days before the start of the proposed Outage
Greater than 90 days	75 days before the start of the proposed Outage

(2) For Outages scheduled at least three days before the scheduled start date of the proposed Outage, ERCOT shall make reasonable attempts to accommodate unusual circumstances that support TSP and DCTO requests for approval earlier than required by the schedule above.

(3) If circumstances prevent adherence to these timetables, ERCOT shall discuss the request status and reason for the delay of the approval with the requesting TSP or

DCTO and make reasonable attempts to mitigate the effect of the delay on the TSP or DCTO.

(4) When ERCOT rejects a request for an Outage, ERCOT shall provide the TSP or DCTO, in written or electronic form, suggested amendments to the schedules of a Planned Outage or Maintenance Outage of Transmission Facilities. Any such suggested amendments accepted by the TSP or DCTO must be processed by ERCOT as a Planned Outage or Maintenance Outage of Transmission Facilities request under this Section.

3.1.5.4 Delay

(1) ERCOT may delay its approval or rejection of a proposed Planned Outage or Maintenance Outage of a Transmission Facilities schedule if the requesting TSP has not submitted sufficient or complete information within the time frames set forth in these Protocols.

[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 may delay its approval or rejection of a proposed Planned Outage or Maintenance Outage of a Transmission Facilities schedule if the requesting TSP or DCTO has not submitted sufficient or complete information within the time frames set forth in these Protocols.

3.1.5.5 Opportunity Outage of Transmission Facilities

(1) Opportunity Outages of Transmission Facilities may be approved under Section 3.1.6.10, Opportunity Outage.

3.1.5.6 Rejection Notice

(1) If ERCOT rejects a request, ERCOT shall provide the TSP a written or electronic rejection notice that includes:

(a) Specific concerns causing the rejection;

(b) Possible remedies or transmission schedule revisions, if any that might mitigate the basis for rejection; and

(c) An electronic copy of the ERCOT study case for review by the TSP.

[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) If ERCOT rejects a request, ERCOT shall provide the TSP or DCTO a written or electronic rejection notice that includes:

(a) Specific concerns causing the rejection;

(b) Possible remedies or transmission schedule revisions, if any that might mitigate the basis for rejection; and

(c) An electronic copy of the ERCOT study case for review by the TSP or DCTO.

(2) ERCOT may reject a Planned Outage or Maintenance Outage of Transmission Facilities only:

(a) To protect system reliability or security;

(b) Due to insufficient information regarding the Outage; or

(c) Due to failure to comply with submittal process requirements, as specified in these Protocols.

(3) When multiple proposed Planned Outages, Maintenance Outages, or Rescheduled Outages cause a reliability or security concern, ERCOT shall:

(a) Communicate with each TSP to see if the TSP will adjust its proposed Planned Outage, Maintenance Outage, or Rescheduled Outage schedule;

(b) Determine if each TSP will agree to an alternative Outage schedule; or

(c) Reject, in ERCOT's sole discretion, one or more proposed Outages, considering order of receipt and impact on the ERCOT Transmission Grid.

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

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

(3) When multiple proposed Planned Outages, Maintenance Outages, or Rescheduled Outages cause a reliability or security concern, ERCOT shall:

(a) Communicate with each TSP and DCTO to see if the TSP or DCTO will adjust its proposed Planned Outage, Maintenance Outage, or Rescheduled Outage schedule;

(b) Determine if each TSP or DCTO will agree to an alternative Outage schedule; or

(c) Reject, in ERCOT's sole discretion, one or more proposed Outages, considering order of receipt and impact on the ERCOT Transmission Grid.

3.1.5.7 Withdrawal of Approval of Approved Planned Outages, Maintenance Outages, and Rescheduled Outages of Transmission Facilities

(1) If ERCOT believes it cannot meet the applicable reliability standards and has exercised reasonable options, ERCOT may contact the TSP for more information prior to its withdrawal of the approval for a Planned Outage, Maintenance Outage, or Rescheduled Outage. ERCOT shall inform the affected TSP both orally and in written or electronic form as soon as ERCOT identifies a situation that may lead to the withdrawal of ERCOT's approval. If ERCOT withdraws its approval, the TSP may submit a new request for approval of the Planned Outage or Maintenance Outage schedule provided the new request meets the submittal requirements for Outage Scheduling.

[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) If ERCOT believes it cannot meet the applicable reliability standards and has exercised reasonable options, ERCOT may contact the TSP or DCTO for more information prior to its withdrawal of the approval for a Planned Outage, Maintenance Outage, or Rescheduled Outage. ERCOT shall inform the affected TSP or DCTO both orally and in written or electronic form as soon as ERCOT identifies a situation that may lead to the withdrawal of ERCOT's approval. If ERCOT withdraws its approval, the TSP or DCTO may submit a new request for approval of the Planned Outage or Maintenance Outage schedule provided the new request meets the submittal requirements for Outage Scheduling.

(2) In determining whether to withdraw approval, ERCOT shall duly consider whether the Planned Outage, Maintenance Outage, or Rescheduled Outage affects public infrastructure if ERCOT is made aware of such potential impacts by the TSP (e.g., impacts on highways, ports, municipalities, and counties).

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

(2) In determining whether to withdraw approval, ERCOT shall duly consider whether the Planned Outage, Maintenance Outage, or Rescheduled Outage affects public infrastructure if ERCOT is made aware of such potential impacts by the TSP or DCTO (e.g., impacts on highways, ports, municipalities, and counties).

(3) Prior to withdrawing the approval of a High Impact Outage (HIO) submitted with greater than 90-days' notice, ERCOT shall coordinate with the TSP and may convert the Planned Outage to a Rescheduled Outage. The Rescheduled Outage shall retain the same priority as the original Planned Outage. ERCOT shall attempt to keep the Outage within the same calendar month.

[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) Prior to withdrawing the approval of a High Impact Outage (HIO) submitted with greater than 90-days' notice, ERCOT shall coordinate with the TSP or DCTO and may convert the Planned Outage to a Rescheduled Outage. The Rescheduled Outage shall retain the same priority as the original Planned Outage. ERCOT shall attempt to keep the Outage within the same calendar month.

3.1.5.8 Priority of Approved Planned, Maintenance, and Rescheduled Outages

(1) In considering TSP requests, ERCOT shall give priority to Planned Outages, Maintenance Outages, and Rescheduled Outages in the order of receipt.

[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) In considering TSP or DCTO requests, ERCOT shall give priority to Planned Outages, Maintenance Outages, and Rescheduled Outages in the order of receipt.

3.1.5.9 Information for Inclusion in Transmission Facilities Outage Requests

(1) Transmission Facilities Outage requests submitted by a TSP must include the following Transmission Facilities-specific information:

(a) The identity of the Transmission Facilities, in the Network Operations Model, including TSP and location;

(b) The nature of the work, by predefined classifications, to be performed during the proposed Transmission Facilities Outage;

(c) The preferred start and finish dates for the proposed Transmission Planned or Maintenance Outage;

(d) The time required to: (i) finish the Transmission Planned Outage or Maintenance Outage and (ii) restore the Transmission Facilities to normal operation;

(e) Primary and alternate telephone numbers for the TSP's Single Point of Contact, as described in Section 3.1.4.1, Single Point of Contact, and the name of the individual submitting the information;

(f) The scheduling flexibility (i.e., the earliest start date and the latest finish date for the Outage);

(g) Any Transmission Facilities that must be out of service to facilitate the TSP's request;

(h) Any remedial actions or special protection systems necessary during the Outage and the contingency that would require the remedial action or relay action; and

(i) Any other relevant information related to the proposed Outage or any unusual risks affecting the schedule.

[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) Transmission Facilities Outage requests submitted by a TSP or a DCTO must include the following Transmission Facilities-specific information:

(a) The identity of the Transmission Facilities, in the Network Operations Model, including TSP or DCTO and location;

(b) The nature of the work, by predefined classifications, to be performed during the proposed Transmission Facilities Outage;

(c) The preferred start and finish dates for the proposed Transmission Planned or Maintenance Outage;

(d) The time required to: (i) finish the Transmission Planned Outage or Maintenance Outage and (ii) restore the Transmission Facilities to normal operation;

(e) Primary and alternate telephone numbers for the TSP's or DCTO's Single Point of Contact, as described in Section 3.1.4.1, Single Point of Contact, and the name of the individual submitting the information;

(f) The scheduling flexibility (i.e., the earliest start date and the latest finish date for the Outage);

(g) Any Transmission Facilities that must be out of service to facilitate the TSP's or DCTO's request;

(h) Any remedial actions or special protection systems necessary during the Outage and the contingency that would require the remedial action or relay action; and

(i) Any other relevant information related to the proposed Outage or any unusual risks affecting the schedule.

3.1.5.10 Additional Information Requests

(1) The requesting TSP shall comply with any ERCOT requests for more information about, or for clarification of, the information submitted by the TSP for a proposed Outage.

[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) The requesting TSP or DCTO shall comply with any ERCOT requests for more information about, or for clarification of, the information submitted by the TSP or DCTO for a proposed Outage.

3.1.5.11 Evaluation of Transmission Facilities Planned Outage or Maintenance Outage Requests

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

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

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

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

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

(c) Forced Outages of Transmission Facilities;

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

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

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

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

(h) Good Utility Practice for Transmission Facilities maintenance.

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

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

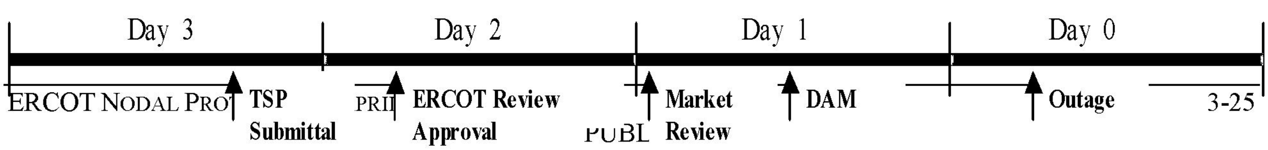
(2) When ERCOT approves a Maintenance Outage, ERCOT shall coordinate the timing of the appropriate course of action with the requesting TSP or DCTO.

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

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

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

3.1.5.12 Submittal Timeline for Transmission Facility Outage Requests



(1) TSPs shall submit all requests for Planned Outages and Maintenance Outages or changes to existing approved Outages of Transmission Elements in the Network Operations Model to ERCOT no later than the minimum amount of time between the submittal of a request to ERCOT for approval of a proposed Outage and the scheduled start date of the proposed Outage, according to the following table:

[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) TSPs and DCTOs shall submit all requests for Planned Outages and Maintenance Outages or changes to existing approved Outages of Transmission Elements in the Network Operations Model to ERCOT no later than the minimum amount of time between the submittal of a request to ERCOT for approval of a proposed Outage and the scheduled start date of the proposed Outage, according to the following table:

Type of Outage	**Minimum amount of time between the Outage request and the scheduled start date of the proposed Outage:**	**Minimum amount of time between any change to an Outage request and the scheduled end date an existing Outage:**
Forced Outage	Immediate	Immediate
Maintenance Outage Level I	Immediate	Immediate
Maintenance Outage Level II	Two days [1]	Two days [1]
Maintenance Outage Level III	Three days	Three days
Planned Outage	Three days	Three days
Simple Transmission Outage	One day	One day

Note:

1. For reliability purposes, ERCOT may reduce to one day on a case-by-case basis.

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 HIOs submitted with 90-days or less notice that are accepted or approved.

3.1.6 Outages of Resources Other than Reliability Resources

(1) Resource Entities should submit a request for a Resource Planned Outage as far in advance of the planned start of the Outage as is practicable but no more than 60 months in advance.

(2) ERCOT shall approve or reject all requested Outage plans for a Resource other than a Reliability Resource submitted to ERCOT more than 45 days before the proposed start date of the Outage.

(a) ERCOT shall approve a requested Outage plan for a Resource other than a Reliability Resource if the proposed approval would not cause the aggregate MW of Resource Outages to exceed the Maximum Daily Resource Planned Outage Capacity at any point during the duration of the proposed Resource Outage, taking into consideration all previously approved Resource Outages.

(3) If a Resource Entity plans to start a Planned or Maintenance Outage within 45 days, and the Resource Entity has not previously submitted a Resource Outage plan for the Outage, then the Resource Entity must immediately notify ERCOT and include in its notice whether the Outage is a Maintenance (Level I, II, or III) Outage or Planned Outage. ERCOT's response to this notification must comply with these requirements:

(a) ERCOT shall accept Levels I, II, and III Maintenance Outage plans, and ERCOT shall coordinate the Outages within the time frames specified in these Protocols.

(b) ERCOT shall approve Planned Outage plans, except that:

(i) ERCOT shall reject an Outage plan if the proposed Outage would cause the aggregate MW of Resource Outages to exceed the Maximum Daily Resource Planned Outage Capacity at any point during the duration of the proposed Outage; and

(ii) ERCOT shall reject an Outage plan if it will impair ERCOT's ability to meet applicable reliability standards, taking into consideration all previously approved and accepted Outages, and other solutions cannot be exercised.

(4) The Resource Entity shall not begin a Planned Outage unless it has received approval of its proposed Outage plan.

(5) ERCOT shall accept Forced Outage plans.

(6) Notwithstanding any other provision of this Section, ERCOT shall approve a requested Outage plan for a nuclear Generation Resource.

(7) Notwithstanding any other provision in this Section, ERCOT shall approve an Outage plan for a Generation Resource that is part of an industrial generation facility if the plan states that the Generation Resource is part of an industrial generation facility, as described in subsection (*l*) of the Public Utility Regulatory Act (PURA), TEX. UTIL. CODE ANN. § 39.151 (Vernon 1998 & Supp. 2007), and that the Outage is necessitated by the operational needs of an industrial Load normally served by the Generation Resource, except that ERCOT is not required to approve the Outage plan if ERCOT determines the Outage will impair ERCOT's ability to ensure transmission security.

3.1.6.1 Receipt of Resource Requests by ERCOT

(1) ERCOT shall acknowledge each request for approval of a Resource Planned Outage plan within two Business Hours of the receipt of the request. ERCOT may request additional information or seek clarification from the Resource Entity regarding the information submitted for a proposed Planned Outage or Maintenance Outage for Resource Facilities.

3.1.6.2 Resource Outage Plan

(1) Resource Outage plans shall include the following information:

(a) The primary and alternate phone number of the Resource Entity's Single Point of Contact for Outage Coordination;

(b) The Resource identified by the name in the Network Operations Model;

(c) The net megawatts of capacity the Resource Entity anticipates will be available during the Outage (if any);

(d) The estimated start and finish dates for each Planned and Maintenance Outage;

(e) An estimate of the acceptable deviation in the Outage schedule (i.e., the earliest start date and the latest finish date for the Outage); and

(f) The nature of work to be performed during the Outage. For a Forced Outage or Forced Derate, the "nature of work" field in the Outage Scheduler shall indicate the best available information about the cause of the Forced Outage or Forced Derate at the time the Outage or derate is entered and shall be updated as soon as more accurate information becomes available.

(2) When ERCOT accepts a Maintenance Outage, ERCOT shall coordinate the timing of the appropriate course of action within the Resource-specified timeframe. The QSE shall notify ERCOT of the Outage and coordinate the time.

3.1.6.3 Additional Information Requests

(1) ERCOT may request additional information from a Resource Entity regarding the information submitted as part of a Resource Outage plan. ERCOT may not unnecessarily delay requests for information in terms of the required response time.

3.1.6.4 Approval of Changes to a Resource Outage Plan

(1) A Resource Entity should request approval as soon as practicable from ERCOT for all changes to a previously approved Resource Outage plan.

(2) A Resource Entity must request approval from ERCOT for all changes to a previously approved Resource Planned Outage.

(a) ERCOT shall approve requests for changes to Resource Planned Outages and Maintenance Outages, except that:

(i) ERCOT shall reject a Resource Outage plan change request if the proposed approval would cause the aggregate MW of Resource Outages to exceed the Maximum Daily Resource Planned Outage Capacity at any point during the duration of the proposed Resource Outage; and

(ii) ERCOT shall reject a Resource Outage plan change request if the proposed approval will impair ERCOT's ability to meet applicable reliability standards, taking into consideration all previously approved and accepted Outages.

(3) Following approval, where ERCOT determines that the Resource Outage plan is expected to result in a violation of an ERCOT reliability criterion or that may result in a cancellation of a Transmission Facilities Planned Outage, ERCOT may discuss such concerns with the Resource Entity or QSE in an attempt to reach a mutually agreeable resolution, including rescheduling the Outage in a manner agreeable to the Resource Entity. If the Transmission Facilities Planned Outage was submitted after the approval of the Resource Planned Outage, the Resource Entity is not required to reschedule the Resource Outage.

(4) When the scheduled work is complete, any Resource may return from a Planned Outage in accordance with Section 3.1.6.11, Outage Returning Early. ERCOT shall accept this change and, in the event that a Transmission Facilities Outage was scheduled concurrently with the affected Resource(s) Outage, ERCOT shall coordinate between the TSP and the Resource Entity to schedule a time mutually agreeable to both parties for the Resource to be On-Line. If mutual agreement cannot be reached, then ERCOT shall decide, considering expected impact on ERCOT System security, future Outage plans, and participants.

3.1.6.5 Evaluation of Proposed Resource Outage

(1) If a proposed Resource Outage, in conjunction with previously accepted Outages, would cause a violation of applicable reliability standards, ERCOT shall:

(a) Communicate with the requesting QSE as required under Section 3.1.6.8, Resource Outage Rejection Notice;

(b) Investigate possible Constraint Management Plans (CMPs) to resolve security violations, based upon security and reliability analysis results and strive to maximize transmission usage consistent with reliable operation; and

(c) Consider modifying the previous acceptance or approval of one or more Transmission Facilities or reliability Resource Outages, considering order of receipt and impact to the ERCOT System.

(2) If transmission security can be maintained using an alternative considered in items (1)(b) and (1)(c) above, then ERCOT may, in its judgment, direct the selected alternatives and approve the proposed Resource Outage.

(3) If ERCOT does not resolve transmission security issues by using the alternatives considered in items (1)(b) and (1)(c) above, then ERCOT shall reject the proposed Resource Outage.

3.1.6.6 Timelines for Response by ERCOT for Resource Planned Outages

(1) ERCOT shall approve or reject each request in accordance with the following table:

Amount of time between a request for approval of a Planned Outage and the scheduled start of the proposed Outage:	Maximum duration of a Planned Outage that may be approved with this lead time:	ERCOT shall approve or reject no later than:
Three days	Seven days	ERCOT shall approve or reject by 1800 hours, two days before the start of the proposed Outage
Between four and eight days	Seven days	ERCOT shall approve or reject by 1800 hours, three days prior to the start of the proposed Outage

Between nine and 15 days	15 days	ERCOT shall approve or reject four days before the start of the requested Outage
Between 16 and 45 days	180 days	ERCOT shall approve or reject within five Business Days after submission
Greater than 45 days but less than 60 months	180 days	ERCOT shall approve or reject within five Business Days after submission
Greater than 60 months	180 days	ERCOT shall approve or reject within five Business Days once the Outage start dates are within the 60-month window

(2) If circumstances prevent adherence to these timetables, ERCOT shall discuss the request status and reason for the delay of decision with the QSE and make reasonable attempts to mitigate the effect of the delay. Furthermore, in its sole discretion, ERCOT may approve Planned Outage durations that exceed the maximum durations prescribed in the table above.

(3) The maximum duration of Planned Outages does not apply for Resource Outages under a Notification of Suspension of Operations (NSO) pursuant to Section 3.14.1.1, Notification of Suspension of Operations.

3.1.6.7 Delay

(1) ERCOT may delay its approval or rejection of a proposed Planned Outage plan if the requesting Resource Entity has not submitted sufficient or complete information within the time frames set forth in this Section 3.1.6, Outages of Resources Other than Reliability Resources. Review periods for Planned Outage consideration do not commence until sufficient and complete information is submitted to ERCOT as described in Section 3.1.6.2, Resource Outage Plan.

3.1.6.8 Resource Outage Rejection Notice

(1) If ERCOT rejects a request for a Planned Outage, ERCOT shall provide the QSE a written or electronic rejection notice that includes:

(a) Specific reasons causing the rejection; or

(b) Possible remedies or Resource schedule revisions, if any, that might mitigate the basis for rejection.

(2) ERCOT may reject a Planned Outage of Resource facilities only:

(a) To protect the reliability or security of the ERCOT System;

(b) Due to insufficient information regarding the Outage;

(c) Due to failure to comply with submittal process requirements, as specified in these Protocols;

(d) To stay within the Maximum Daily Resource Planned Outage Capacity; or

(e) As specified elsewhere in these Protocols.

(3) When multiple proposed Planned Outages or Maintenance Outages cause a known capacity conflict, ERCOT shall:

(a) Communicate with each QSE to see if the QSE will adjust its proposed Planned Outage schedule;

(b) Determine if each QSE will agree to an alternative Outage schedule; or

(c) Reject, in ERCOT's sole discretion, one or more proposed Outages, considering order of receipt and impact to the ERCOT System.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(iv) The QSE must update the Resource's Energy Offer Curve to $4,500/MWh for all MW levels from 0 MW to the High Sustained Limit (HSL) when the High System-Wide Offer Cap (HCAP) is in effect. If the Low-System Wide Offer Cap (LCAP) is in effect, the QSE must update the Resource's Energy Offer Curve equal to LCAP for all MW levels from 0 MW to HSL; and

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

(iv) ERCOT shall create proxy Energy Offer Curves for the Resource under paragraph (4)(d)(iii) of Section 6.5.7.3, Security Constrained Economic Dispatch; and

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

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

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

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

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

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

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

the preliminary OAE to the ERCOT website within an hour of issuing an AAN, including but not limited to:

(a) The Load forecast;

(b) Load forecast vendor selection;

(c) Wind forecast;

(d) Wind forecast vendor selection;

(e) Solar forecast;

(f) Solar forecast vendor selection;

(g) Expected severe weather impacts forecast;

(h) Targeted reserve levels;

(i) DC Tie import forecast;

(j) DC Tie export curtailment forecast;

(k) SODG and SOTG forecasts;

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

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

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

[NPRR995: Replace paragraph (7) above with the following upon system implementation:]

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

(a) The Load forecast;

(b) Load forecast vendor selection;

(c) Wind forecast;

(d) Wind forecast vendor selection;

(e) Solar forecast;

(f) Solar forecast vendor selection;

(g) Expected severe weather impacts forecast;

(h) Targeted reserve levels;

(i) DC Tie import forecast;

(j) DC Tie export curtailment forecast;

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

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

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

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

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

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

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

3.1.6.10 Opportunity Outage

(1) Opportunity Outages for Resources are a special category of Planned Outages that may be approved by ERCOT when a specific Resource has been forced Off-Line due to a Forced Outage and the Resource has been previously approved for a Planned Outage during the next two days.

(2) When a Forced Outage occurs on a Resource that has an approved Outage scheduled within the following two days, the Resource may remain Off-Line and start the approved Outage earlier than scheduled. The QSE must give as much notice as practicable to ERCOT.

(3) Opportunity Outages of Transmission Facilities may be approved by ERCOT when a specific Resource is Off-Line due to a Forced, Planned or Maintenance Outage. A TSP may request an Opportunity Outage at any time.

(4) When an Outage occurs on a Resource that has an approved Transmission Facilities Opportunity Outage request on file, the TSP may start the approved Outage as soon as practical after receiving authorization to proceed by ERCOT. ERCOT must give as much notice as practicable to the TSP.

3.1.6.11 Outage Returning Early

(1) A Resource that completes a Planned Outage early and wants to resume operation shall notify ERCOT of the early return prior to resuming service by making appropriate entries in the Current Operating Plan or Outage Scheduler if applicable as much in advance as practicable, but not later than at least two hours prior to beginning startup. Within two hours of receiving such request, ERCOT shall either:

(a) Approve the request unless, as a result of complying with the request, ERCOT cannot maintain system reliability or security with the Resource injection. In such a case, ERCOT shall issue a Verbal Dispatch Instruction (VDI) to the Resource's QSE to stay Off-Line; or

(b) Coordinate between the TSP and Resource Entity to schedule a time agreeable to both parties for the Resource to be Off-Line in the event if that a Transmission Facilities Outage requires the affected Resource to be Off-Line. If mutual agreement is not reached, then ERCOT shall decide on the appropriate time, after considering expected impacts on system security, future Outage plans, and participants and issue a VDI to the Resource's QSE to stay Off-Line.

(2) Before an early return from an Outage, a Resource Entity or QSE may inquire of ERCOT whether the Resource is expected to be decommitted by ERCOT upon its early return. If a Resource Entity or QSE is notified by ERCOT that the Resource will be decommitted if it returns early and the Resource Entity or QSE starts the Resource within the previously accepted or approved Outage period, then the QSE representing the Resource will not be

paid any decommitment compensation as otherwise would be provided for in Section 5.7, Settlement for RUC Process.

3.1.6.12 Resource Coming On-Line

(1) Before start-up and synchronizing On-Line, a Resource Entity or QSE may inquire of ERCOT whether the Resource is expected to be decommitted by ERCOT upon its coming On-Line. If a Resource Entity or QSE is notified by ERCOT that the Resource will be decommitted if the Resource comes On-Line and the Resource Entity or QSE starts the Resource, then the QSE representing the Resource will not be paid any decommitment compensation as otherwise would be provided for in Section 5.7.3, Payment When ERCOT Decommits a QSE-Committed Resource.

3.1.6.13 Maximum Daily Resource Planned Outage Capacity

(1) ERCOT shall calculate a maximum capacity of Resource Planned Outages, excluding Outages of nuclear-powered generation facilities and Outages of QFs that are subject to the exemption in paragraph (7) of Section 3.1.6, Outages of Resources Other than Reliability Resources, that should be allowed on each day of the next 60 months.

(a) For days more than seven days ahead of the Operating Day, the calculation of this Maximum Daily Resource Planned Outage Capacity will be based on seasonal assumptions, planned Resources that have met the criteria in Planning Guide Section 6.9, Addition of Proposed Generation to the Planning Models, Planned Outages of nuclear Generation Resources, Planned Outages of QFs that are subject to the exemption in paragraph (7) of Section 3.1.6, and the long-term Load forecast. ERCOT shall update the calculation of the Maximum Daily Resource Planned Outage Capacity for the next 60 months twice per month.

(b) For days that are seven days or less prior to the Operating Day, the calculation of this Maximum Daily Resource Planned Outage Capacity will be based on the inputs used for the planning assessment for an OAE described in Section 3.1.6.9, Withdrawal of Approval and Rescheduling of Approved Planned Outages of Resource Facilities. ERCOT shall update the calculation of the Maximum Daily Resource Planned Outage Capacity for each hour of the next seven days on a rolling daily basis.

(c) ERCOT shall post the Maximum Daily Resource Planned Outage Capacity and aggregate MW of approved Resource Planned Outages at least twice per day on the ERCOT website for each day of the next 60 months.

(d) ERCOT shall post the Maximum Daily Resource Planned Outage Capacity and aggregate MW of approved Resource Planned Outages hourly on the ERCOT website for each hour of the next seven days.

(2) ERCOT may adjust the Maximum Daily Resource Planned Outage Capacity if, at any point in time, the actual aggregate Forced Outages and Maintenance Outages exceed the amount that is used in the assessment of the Maximum Daily Resource Planned Outage Capacity.

(3) ERCOT shall post on the ERCOT website the methodology it uses to calculate the Maximum Daily Resource Planned Outage Capacity in accordance with the parameters established by paragraphs (1) and (2) above. The methodology and any revisions thereto shall be approved by the ERCOT Board of Directors. ERCOT shall issue a Market Notice describing any revision and the justification for such revision and shall provide at least 14 days for stakeholder comment on the proposed revision unless ERCOT determines that, due to an actual or anticipated Emergency Condition, a shorter comment period is warranted. Upon adopting a change to the methodology, ERCOT shall post the revised methodology on the ERCOT website and issue a Market Notice announcing the posting.

3.1.6.14 Distribution Facility Outages Impacting Distribution Generation Resources and Distribution Energy Storage Resources

(1) A Distribution Service Provider (DSP) must notify the party designated by the Distribution Generation Resource (DGR) or Distribution Energy Storage Resource (DESR) (Resource Entity or QSE) if the DSP plans to take an outage on any distribution facility that will impact the operation of a DGR or DESR. The Resource Entity for the DGR or DESR shall submit a Planned or Maintenance Resource Outage, as appropriate, to reflect the unavailability of the Resource due to the DSP outage. ERCOT may not reject a DGR or DESR Outage taken due to a DSP system outage, nor may ERCOT require the DSP to reschedule the outage. However, ERCOT may consult with the DSP about rescheduling the outage.

3.1.7 Reliability Resource Outages

(1) ERCOT shall evaluate requests for approval of an Outage of a Reliability Resource to determine if any one or a combination of proposed Outages may cause ERCOT to violate applicable reliability standards or exceed the Maximum Daily Resource Planned Outage Capacity. ERCOT's evaluations shall take into consideration factors including the following:

(a) Load forecast;

(b) All other known Outages; and

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

3.1.7.1 Timelines for Response by ERCOT on Reliability Resource Outages

(1) ERCOT shall approve requests for Planned Outages of Reliability Resources unless, in ERCOT's determination, the requested Planned Outage would cause ERCOT to violate applicable reliability standards or exceed the Maximum Daily Resource Planned Outage Capacity. ERCOT shall approve or reject each request in accordance with the following table:

Amount of time between a Request for approval of a proposed Planned Outage and the scheduled start date of the proposed Outage:	ERCOT shall approve or reject no later than:
No less than 30 days	Five Business Days after submission
Greater than 45 days	Five Business Days after submission

(2) ERCOT shall approve requests for Outages, other than Forced Outages or Level I Maintenance Outages, of Reliability Resources unless, in ERCOT's determination, the requested Outage would cause ERCOT to violate applicable reliability standards or exceed the Maximum Daily Resource Planned Outage Capacity. ERCOT shall approve or reject Maintenance Outages on Reliability Resources as follows:

Amount of time between a Request for approval of a proposed Outage and the scheduled start date of the proposed Outage:	ERCOT shall approve or reject no later than:
Between three and eight days	0000 hours, two days before the start of the proposed Outage
Between nine and 30 days	Four days before the start of the proposed Outage

(3) ERCOT shall not be deemed to have approved the Outage request associated with the Planned Outage until ERCOT notifies the Single Point of Contact of its approval. ERCOT shall transmit approvals electronically.

(4) ERCOT, at its sole discretion, may relax the submission timing requirements in this Section.

3.1.7.2 Changes to an Approved Reliability Resource Outage Plan

(1) Once ERCOT has approved a Reliability Resource Planned Outage, the Resource Entity for the Reliability Resource may submit to ERCOT a change request by entering the change in the Outage Scheduler no later than 30 days before the scheduled start date of the approved Outage. ERCOT shall approve or reject the proposed change within 15 days of receiving the change request form. ERCOT may, at its discretion, relax the 30 day Notice requirement.

3.1.8 High Impact Transmission Element (HITE) Identification

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

3.2 Analysis of Resource Adequacy

3.2.1 Calculation of Aggregate Resource Capacity

(1) ERCOT shall use Outages in the Outage Scheduler and, when applicable, the Resource Status from the Current Operating Plan (COP) to calculate the aggregate capacity from Generation Resources and Load Resources projected to be available in the ERCOT Region and in Forecast Zones in ERCOT. "Forecast Zones" have the same boundaries as the 2003 ERCOT Congestion Management Zones (CMZs). Each Resource will be mapped to a Forecast Zone during the registration process.

[NPRR1014 and NPRR1029: Replace applicable portions of paragraph (1) above with the following upon system implementation:]

(1) ERCOT shall use Outages in the Outage Scheduler and, when applicable, the Resource Status from the Current Operating Plan (COP) to calculate the aggregate capacity from Generation Resources, Energy Storage Resources (ESRs), and Load Resources projected to be available in the ERCOT Region and in Forecast Zones in ERCOT. "Forecast Zones" have the same boundaries as the 2003 ERCOT Congestion Management Zones (CMZs). Each Resource will be mapped to a Forecast Zone during the registration process.

(2) On a rolling hourly basis, ERCOT shall calculate the aggregate hourly Generation Resource capacity and Load Resource capacity in the ERCOT Region and Forecast Zones projected to be available during each hour for the following seven days.

[NPRR1014 and NPRR1029: Replace applicable portions of paragraph (2) above with the following upon system implementation:]

(2) On a rolling hourly basis, ERCOT shall calculate the aggregate hourly Generation Resource capacity, ESR capacity, and Load Resource capacity in the ERCOT Region and Forecast Zones projected to be available during each hour for the following seven days.

(3) Projections of Generation Resource capacity from Intermittent Renewable Resources (IRRs) shall be consistent with capacity availability estimates, such as the effective Load carrying capability of wind, developed jointly between ERCOT and the appropriate Technical Advisory Committee (TAC) subcommittee and approved by the ERCOT Board

or typical production expectations consistent with expected wind profiles as appropriate for the scenario being studied.

[NPRR1029: Replace paragraph (3) above with the following upon system implementation:]

(3) Projections of generation capacity from Intermittent Renewable Resources (IRRs) and the intermittent renewable generation components of DC-Coupled Resources shall be consistent with capacity availability estimates, such as the effective Load carrying capability of wind, developed jointly between ERCOT and the appropriate Technical Advisory Committee (TAC) subcommittee and approved by the ERCOT Board or typical production expectations consistent with expected wind profiles as appropriate for the scenario being studied.

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

3.2.2 Demand Forecasts

(1) Monthly, ERCOT shall develop 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, 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.

3.2.3 Short-Term System Adequacy Reports

(1) ERCOT shall generate and post short-term adequacy reports on the ERCOT website. ERCOT shall update these reports hourly following updates to the Seven-Day Load Forecast, except where noted otherwise. The short-term adequacy reports will provide:

(a) For Generation Resources, the available On-Line Resource capacity for each hour, aggregated by Forecast Zone, using the COP for the first seven days and considering Resources with a COP Resource Status listed in paragraph (5)(b)(i) of Section 3.9.1, Current Operating Plan (COP) Criteria;

(b) The total system-wide capacity of Resource Outages as reflected in the Outage Scheduler that are accepted or approved. The Resource Outage capacity amount shall be based from each Resource's current Seasonal High Sustained Limit (HSL) and posted each hour for the top of each Operating Hour for the next 168 hours. This posted information will exclude specific Resource information and Outages related to Mothballed or Decommissioned Generation Resources, and will be aggregated on a Forecast Zone basis in three categories:

(i) IRRs with an Outage Scheduler nature of work other than "New Equipment Energization";

(ii) Other Resources with an Outage Scheduler nature of work other than "New Equipment Energization"; and

(iii) Resources with an Outage Scheduler nature of work "New Equipment Energization";

(c) For Load Resources, the available capacity for each hour aggregated by Forecast Zone, using the COP for the first seven days and considering Resources with a COP Resource Status of ONRGL, ONCLR, or ONRL;

(d) Forecast Demand for each hour described in Section 3.2.2, Demand Forecasts;

(e) For Generation Resources, the available Off-Line Resource capacity that can be started for each hour, aggregated by Forecast Zone, using the COP for the first seven days and considering Resources with a COP Resource Status of OFF or OFFNS and temporal constraints; and

(f) Following each Hourly Reliability Unit Commitment (HRUC), the available On-Line capacity from Generation Resources, aggregated by Forecast Zone, based on Real-Time telemetry, for which the COP Resource Status is OFF, OUT, or EMR for all hours within the HRUC Study Period. The available On-Line capacity will consider those Resources with a Real-Time Resource Status listed in paragraph (5)(b)(i) of Section 3.9.1 excluding SHUTDOWN.

(g) The available capacity for each hour for the next seven days. For day one, and for day two following the execution of the Day-Ahead Reliability Unit Commitment (DRUC) on day one, the available capacity will be the sum of the values calculated in paragraphs (a) and (e) above, except that for IRRs the forecasted output will be used instead of COP values, and Direct Current Tie (DC Tie) exports will be subtracted. For the remaining hours of the seven days, the available capacity will be calculated as the sum of the Seasonal HSLs for non-IRR Generation Resources including seasonal Private Use Network capacity and the forecasted output for IRRs minus the total capacity of accepted or approved Resource Outages.

(h) The available capacity for reserves for each hour, which will be the available capacity calculated in paragraph (g) above minus the forecasted Demand for that hour.

[NPRR962, NPRR1007, and NPRR1029: Replace applicable portions of Section 3.2.3 above with the following upon system implementation for NPRR962 or NPRR1029; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007:]

3.2.3 Short-Term System Adequacy Reports

(1) ERCOT shall generate and post short-term adequacy reports on the ERCOT website. ERCOT shall update these reports hourly following updates to the Seven-Day Load Forecast, except where noted otherwise. The short-term adequacy reports will provide:

(a) For Generation Resources, the available On-Line Resource capacity for each hour, aggregated by Forecast Zone, using the COP for the first seven days and considering Resources with a COP Resource Status listed in paragraph (5)(b)(i) of Section 3.9.1, Current Operating Plan (COP) Criteria;

(b) The total system-wide capacity of Resource Outages as reflected in the Outage Scheduler that are accepted or approved. The Resource Outage capacity amount shall be based from each Resource's current Seasonal High Sustained Limit (HSL) and posted each hour for the top of each Operating Hour for the next 168 hours. This posted information will exclude specific Resource information and Outages related to Mothballed or Decommissioned Generation Resources, and will be aggregated on a Forecast Zone basis in three categories:

(i) IRRs and the intermittent renewable generation component of each DC-Coupled Resource with an Outage Scheduler nature of work other than "New Equipment Energization";

(ii) Other Resources with an Outage Scheduler nature of work other than "New Equipment Energization"; and

(iii) Resources with an Outage Scheduler nature of work "New Equipment Energization";

(c) For Load Resources, the available capacity for each hour aggregated by Forecast Zone, using the COP for the first seven days and considering Resources with a COP Resource Status of ONL;

(d) The total capability of Resources available to provide the following Ancillary Service combinations, using COPs submitted by QSEs for the first seven days and capped by the COP limits for individual Resources. A Resource's capability shall only be included in the sums below if the Resource Status allows the Resource to provide at least one of the Ancillary Services within the sum:

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

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

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

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

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

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

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

(viii) Capacity to provide Reg-Down;

(e) Forecast Demand for each hour described in Section 3.2.2, Demand Forecasts;

(f) For Generation Resources, the available Off-Line Resource capacity that can be started for each hour, aggregated by Forecast Zone, using the COP for the first seven days and considering Resources with a COP Resource Status of OFF and temporal constraints; and

(g) Following each Hourly Reliability Unit Commitment (HRUC), the available On-Line capacity from Generation Resources, aggregated by Forecast Zone, based on Real-Time telemetry, for which the COP Resource Status is OFF, OUT, or EMR for all hours within the HRUC Study Period. The available On-Line capacity will consider those Resources with a Real-Time Resource Status listed in paragraph (5)(b)(i) of Section 3.9.1 excluding SHUTDOWN.

(h) For each Direct Current Tie (DC Tie), the sum of any ERCOT-approved DC Tie Schedules for each 15-minute interval for the first seven days. The sum shall be displayed as an absolute value and classified as a net import or net export.

(i) The available capacity for each hour for the next seven days. For day one, and for day two following the execution of the Day-Ahead Reliability Unit

Commitment (DRUC) on day one, the available capacity will be the sum of the values calculated in paragraphs (a) and (f) above, except that for IRRs the forecasted output will be used instead of COP values, and DC Tie exports will be subtracted. For the remaining hours of the seven days, the available capacity will be calculated as the sum of the Seasonal HSLs for non-IRR Generation Resources including seasonal Private Use Network capacity and the forecasted output for IRRs minus the total capacity of accepted or approved Resource Outages.

(j) The available capacity for reserves for each hour, which will be the available capacity calculated in paragraph (i) above minus the forecasted Demand for that hour.

3.2.4 [RESERVED]

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: Replace paragraph (g) above with the following upon system implementation:]

(h) 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), 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