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

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

3.10.2 Annual Planning Model

(1) For each of the next six years, ERCOT shall develop models for annual planning purposes that contain, as much as practicable, information consistent with the Network Operations Model. The "Annual Planning Model" for each of the next six years is a model of the ERCOT power system (created, approved, posted, and updated regularly by ERCOT) as it is expected to operate during peak Load conditions for the corresponding future year.

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

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

(4) ERCOT shall post the schedule for updating transmission information on the MIS Secure Area.

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

3.10.3 CRR Network Model

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

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

(3) Each CRR Network Model must include:

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

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

(c) Generation Resource locations;

(d) Transmission Elements;

(e) Transmission impedances;

(f) Transmission ratings, excluding Relay Loadability Ratings;

(g) Contingency lists;

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

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

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

3.10.3.1 Process for Managing Network Operations Model Updates for Point of Interconnection Bus Changes, Resource Retirements and Deletion of DC Tie Load Zones

(1) Following the permanent change in Point of Interconnection Bus (POIB) of all Resources associated with a Resource Node, ERCOT shall retain the associated Settlement Point in the Network Operations Model at its existing location, an electrically similar location, or until all outstanding CRRs associated with that Settlement Point have expired as

determined in accordance with the Other Binding Document, "Procedure for Identifying Resource Nodes." Following the retirement of all Resources associated with a Resource Node, ERCOT shall move the Resource Node to a proxy Electrical Bus. The proxy Electrical Bus will be selected by finding the nearest energized Electrical Bus with the least impedance equipment between the existing Resource Node and the proxy Electrical Bus. For purposes of the CRR Auction model for calendar periods that are prior to the expiration date of all CRRs associated with the Settlement Point, the Settlement Point will continue to be available as a sink or source for CRR Auction transaction submittals. For calendar periods that are beyond the expiration date of all CRRs associated with the Settlement Point, the Settlement Point will not be available for transaction submittals in the associated CRR Auctions. The Settlement Point will be removed from the Network Operations Model once all associated CRRs have expired.

(2) When a Direct Current Tie (DC Tie) is to be permanently removed from service, ERCOT will delete the associated DC Tie Load Zone from the Network Operations Model after all outstanding CRRs associated with that DC Tie Load Zone have expired. The DC Tie Load Zone will continue to be available as a sink or source Settlement Point for transaction submittals in CRR Auctions for calendar periods that are prior to the scheduled deletion date of the DC Tie Load Zone; however, the DC Tie Load Zone will no longer be an available Settlement Point for transaction submittals in CRR Auctions for calendar periods that are after the scheduled deletion date of the DC Tie Load Zone.

3.10.4 ERCOT Responsibilities

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

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

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

(4) ERCOT shall install EMS test and simulation facilities that accommodate execution of the State Estimator and LMP calculator, respectively. These facilities will be used to

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

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

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

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

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

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

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

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

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

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

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

3.10.5 TSP Responsibilities

(1) Each TSP shall design, implement, operate, and maintain its systems to meet the requirements of Section 3.10.7.5, Telemetry Requirements, for measurements facilitating the observability of the Electrical Buses used for Security-Constrained Economic Dispatch (SCED). However, there is no obligation to re-construct or retrofit already

existing installations except as shown to be needed in order to comply with Section 3.10.7.5 and Section 3.10.9, State Estimator Requirements.

(2) TSPs shall add telemetry to equipment it owns and directly operates and controls at ERCOT's request to maintain observability and redundancy requirements as specified herein, and under Section 3.10.7.5. Nothing in this subsection prohibits a TSP from adding telemetry to equipment it does not own but directly operates and controls. ERCOT shall request such additions when a lack of data telemetry has caused, or can be demonstrated to result in, inaccuracies between Real-Time measurements and modeling outcomes that could result in incorrect LMP prices or potential reliability problems.

(3) Each TSP shall provide to ERCOT planned construction information, including Certificate of Convenience and Necessity (CCN) application milestone dates if applicable, all of which shall be updated according to a schedule established by ERCOT.

(4) Each TSP shall provide to ERCOT project status updates of Transmission Facilities that are part of an Reliability Must-Run (RMR) or Must Run Alternative (MRA) exit strategy corresponding to a specific RMR or MRA Agreement that has not been terminated, which shall be updated by the first Business Day of each month, noting any acceleration or delay in planned completion date.

(5) A QSE must receive approval from a TSP prior to using the TSP's telemetry as part of a Generation Resource's Bulk Electric System protection scheme or for generation control. If a TSP has approved a QSE's use of the TSP's telemetry, the TSP shall inform the QSE of any telemetry changes with reasonable notice prior to the change or where prior notice is not possible as soon as reasonably practicable thereafter, including discontinuation of the TSP's provision of such telemetry, and the timeline for the changes.

[NPRR857: Replace Section 3.10.5 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:]

3.10.5 TSP and DCTO Responsibilities

(1) Each TSP and DCTO shall design, implement, operate, and maintain its systems to meet the requirements of Section 3.10.7.5, Telemetry Requirements, for measurements facilitating the observability of the Electrical Buses used for Security-Constrained Economic Dispatch (SCED). However, there is no obligation to re-construct or retrofit already existing installations except as shown to be needed in order to comply with Section 3.10.7.5 and Section 3.10.9, State Estimator Requirements.

(2) Each TSP and DCTO shall add telemetry to equipment it owns and directly operates and controls at ERCOT's request to maintain observability and redundancy requirements as

specified herein, and under Section 3.10.7.5. Nothing in this subsection prohibits a TSP from adding telemetry to equipment it does not own but directly operates and controls. ERCOT shall request such additions when a lack of data telemetry has caused, or can be demonstrated to result in, inaccuracies between Real-Time measurements and modeling outcomes that could result in incorrect LMP prices or potential reliability problems.

(3) Each TSP and DCTO shall provide to ERCOT planned construction information, including Certificate of Convenience and Necessity (CCN) application milestone dates if applicable, all of which shall be updated according to a schedule established by ERCOT.

(4) Each TSP shall provide to ERCOT project status updates of Transmission Facilities that are part of an Reliability Must-Run (RMR) or Must Run Alternative (MRA) exit strategy corresponding to a specific RMR or MRA Agreement that has not been terminated, which shall be updated by the first Business Day of each month, noting any acceleration or delay in planned completion date.

(5) A QSE must receive approval from a TSP prior to using the TSP's telemetry as part of a Generation Resource's Bulk Electric System protection scheme or for generation control. If a TSP has approved a QSE's use of the TSP's telemetry, the TSP shall inform the QSE of any telemetry changes with reasonable notice prior to the change or where prior notice is not possible as soon as reasonably practicable thereafter, including discontinuation of the TSP's provision of such telemetry, and the timeline for the changes.

3.10.6 QSE and Resource Entity Responsibilities

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

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

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

(2) QSEs shall ensure availability of telemetry to generation and transmission equipment its Resource Entity owns at ERCOT's request to maintain observability and redundancy requirements as specified herein, and under Section 3.10.7.5, Telemetry Requirements.

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

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

(a) Cold weather temperature limits:

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

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

(iii) At least one of the following:

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

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

(iv) At least one of the following:

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

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

(b) Hot weather temperature limits:

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

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

(iii) At least one of the following:

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

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

(iv) At least one of the following:

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

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

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

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

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

3.10.7 ERCOT System Modeling Requirements

(1) The following subsections contain the fidelity requirements for the ERCOT Network Operations Model.

3.10.7.1 Modeling of Transmission Elements and Parameters

(1) ERCOT, each TSP, and each Resource Entity shall coordinate to define each Transmission Element such that the TSP's control center operational model and ERCOT's Network Operations Model are consistent.

[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 coordinate to define each Transmission Element such that the TSP's control center operational model and ERCOT's Network Operations Model are consistent.

(2) Each Transmission Element must have a unique identifier using a consistent naming convention used between ERCOT, Resource Entities, and TSPs. ERCOT shall develop the naming convention with the assistance of the TSP and the approval of the Technical Advisory Committee (TAC). In addition to the Network Operations Model releases described in Section 3.10.1, Time Line for Network Operations Model Change Requests, ERCOT shall provide all names and parameters of all Transmission Elements to Market Participants posted on MIS Secure Area by 0600 each day.

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

(2) Each Transmission Element must have a unique identifier using a consistent naming convention used between ERCOT, Resource Entities, TSPs, and DCTOs. ERCOT shall develop the naming convention with the assistance of the TSP and the approval of TAC. In addition to the Network Operations Model releases described in Section 3.10.1, Time Line for Network Operations Model Change Requests, ERCOT shall provide all names

and parameters of all Transmission Elements to Market Participants posted on MIS Secure Area by 0600 each day.

(3) If the responsible TSP submits a NOMCR for non-operational changes, such as name changes for Transmission Elements, ERCOT shall implement the request.

[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) If the responsible TSP or DCTO submits a NOMCR for non-operational changes, such as name changes for Transmission Elements, ERCOT shall implement the request.

(4) Resource Entities shall provide the data requested in this Section through the Resource Registration data provided pursuant to Planning Guide Section 6.8.2, Resource Registration Process.

[NPRR857: Replace paragraph (4) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(4) Each Resource Entity shall provide the data requested in this Section through the Resource Registration data provided pursuant to relevant authorities, including Planning Guide Section 6.8.2, Resource Registration Process.

[NPRR1133: Insert paragraph (5) below upon system implementation of NPRR857:]

(5) Each DC Tie Facility owner shall provide the model data needed to accurately reflect the physical characteristics of the DC Tie Facility in ERCOT's Network Operations Model to its DCTO, and the DCTO shall submit the data to ERCOT. The DC Tie Facility owner is responsible for the accuracy and completeness of the data submitted to ERCOT through its DCTO.

3.10.7.1.1 Transmission Lines

(1) ERCOT shall model each transmission line that operates in excess of 60 kV.

(2) For each of its transmission lines operated as part of the ERCOT Transmission Grid, each TSP and if applicable, Resource Entity, shall provide ERCOT with the following information consistent with the ratings methodology prescribed in 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) For each of its transmission lines operated as part of the ERCOT Transmission Grid, each TSP, DCTO, and if applicable, Resource Entity, shall provide ERCOT with the following information consistent with the ratings methodology prescribed in the ERCOT Operating Guides:

(a) Equipment owner(s);

(b) Equipment operator(s);

(c) Transmission Element name;

(d) Line impedance;

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

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

(3) The TSP and Resource Entity may submit special transfer limits and stability limits for secure and reliable grid operations for ERCOT approval. ERCOT has sole decision-making authority and responsibility to determine the limits to be applied in grid operations.

[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) The TSP, DCTO, and Resource Entity may submit special transfer limits and stability limits for secure and reliable grid operations for ERCOT approval. ERCOT has sole decision-making authority and responsibility to determine the limits to be applied in grid operations.

(4) The TSP and Resource Entity may implement protective relay and control systems and set values appropriate to de-energize faulted equipment and meet the TSP and Resource Entity obligations for public or employee safety, and when necessary to prevent in-service or premature equipment failure consistent with Good Utility Practice and accepted industry standards. The TSP and Resource Entity shall include those limits as Relay Loadability Ratings when providing ERCOT with ratings or proposed transfer limits.

[NPRR857: Replace paragraph (4) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(4) The TSP, DCTO, and Resource Entity may implement protective relay and control systems and set values appropriate to de-energize faulted equipment and meet the TSP, DCTO, and Resource Entity obligations for public or employee safety, and when necessary to prevent in-service or premature equipment failure consistent with Good Utility Practice and accepted industry standards. The TSP, DCTO, and Resource Entity shall include those limits as Relay Loadability Ratings when providing ERCOT with ratings or proposed transfer limits.

(5) The Network Operations Model must use rating categories for Transmission Elements as defined in the ERCOT Operating Guides.

3.10.7.1.2 Transmission Buses

(1) ERCOT shall model each Electrical Bus that operates as part of the ERCOT Transmission Grid in excess of 60 kV and that is required to model switching stations or transmission Loads.

(2) Each TSP and if applicable, Resource Entity, shall provide ERCOT with the following information, subject to the naming conventions in Section 3.10.7.1, Modeling of Transmission Elements and Parameters:

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

(2) Each TSP, DCTO, and if applicable, Resource Entity, shall provide ERCOT with the following information, subject to the naming conventions in Section 3.10.7.1, Modeling of Transmission Elements and Parameters:

(a) Equipment owner(s);

(b) Equipment operator(s);

(c) The Transmission Element name;

(d) The substation name;

(e) A description of all transmission circuits that may be connected through breakers or switches; and

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

(3) To accommodate the Outage Scheduler, the TSP and Resource Entity may define a separate name and Transmission Element for any Electrical Bus that can be physically separated by a manual switch or breaker within a substation.

[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) To accommodate the Outage Scheduler, the TSP, DCTO, and Resource Entity may define a separate name and Transmission Element for any Electrical Bus that can be physically separated by a manual switch or breaker within a substation.

3.10.7.1.3 Transmission Breakers and Switches

(1) ERCOT's Network Operations Model must include all transmission breakers and switches, the operation of which may cause a change in the flow on transmission lines or Electrical Buses. Breakers and switches may only be connected to defined Electrical Buses.

(2) Each TSP and Resource Entity shall provide ERCOT with the following information, subject to the naming conventions in Section 3.10.7.1, Modeling of Transmission Elements and Parameters:

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

(2) Each TSP, DCTO, and Resource Entity shall provide ERCOT with the following information, subject to the naming conventions in Section 3.10.7.1, Modeling of Transmission Elements and Parameters:

(a) Equipment owner(s);

(b) Equipment operator(s);

(c) The Transmission Element name;

(d) The substation name;

(e) Connectivity;

(f) Normal status;

(g) Synchronism check relay phase angle limits that are applied to operator-initiated, non-automated control actions of TSP-owned transmission breakers; and

[NPRR857: Replace item (g) 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:]

(g) Synchronism check relay phase angle limits that are applied to operator-initiated, non-automated control actions of TSP-owned or DCTO-owned transmission breakers; and

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

(3) ERCOT shall develop methods to accurately model changes in transmission line loading resulting from Load rollover schemes transferring more than ten MW. This may include modeling distribution circuit breakers, dead line sensing, or other methods that signal when the Load should be transferred from one transmission line to another transmission line. ERCOT may employ heuristic rule sets for all manual Load transfers and for automated transfers where feasible. ERCOT application software is required to model the effects of automatic or manual schemes in the field transfer Load under line outage conditions. Each TSP and as applicable, Resource Entity, shall define the Load rollover schemes under Section 3.10.7.2, Modeling of Resources and Transmission Loads, and furnish this information to ERCOT. Transmission field (right-of-way) switches must be connected to a named Electrical Bus and be included in the Network Operations Model.

[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) ERCOT shall develop methods to accurately model changes in transmission line loading resulting from Load rollover schemes transferring more than ten MW. This may include modeling distribution circuit breakers, dead line sensing, or other methods that signal when the Load should be transferred from one transmission line to another transmission line. ERCOT may employ heuristic rule sets for all manual Load transfers and for automated transfers where feasible. ERCOT application software is required to model the effects of automatic or manual schemes in the field transfer Load under line outage conditions. Each TSP and as applicable, each DCTO and Resource Entity, shall define the Load rollover schemes under Section 3.10.7.2, Modeling of Resources and Transmission Loads, and furnish this information to ERCOT. Transmission field (right-of-way) switches must be connected to a named Electrical Bus and be included in the Network Operations Model.

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

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

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

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

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

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

(a) Equipment owner(s);

(b) Equipment operator(s);

(c) The Transmission Element name;

(d) The substation name;

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

(f) Connectivity;

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

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

(4) The Resource Entity shall provide parameters for each MPT to ERCOT as part of the Resource Registration data pursuant to Planning Guide Section 6.8.2, Resource Registration Process. ERCOT shall provide the information to TSPs. Each TSP shall coordinate with the operators of the Resources connected to their respective systems to

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

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

3.10.7.1.5 Reactors, Capacitors, and other Reactive Controlled Sources

(1) ERCOT shall model all controlled reactive devices. Each Market Participant shall provide ERCOT with complete information on each device's capabilities and normal switching schema.

(2) Each Market Participant shall provide ERCOT with the following information, subject to the naming conventions in Section 3.10.7.1, Modeling of Transmission Elements and Parameters:

(a) Equipment owner(s);

(b) Equipment operator(s);

(c) The Transmission Element name;

(d) The substation name;

(e) Voltage or time switched on;

(f) Voltage or time switched off;

(g) Associated switching device name;

(h) Connectivity;

(i) Nominal voltage and associated capacitance or reactance; and

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

(3) The ERCOT Operating Guides must include parameters for standard reactor and capacitor switching plans for use in the Network Operations Model. ERCOT shall model the devices under Section 3.10.4, ERCOT Responsibilities, in all applicable ERCOT applications and systems. ERCOT shall provide copies of the switching plan to the

Market Participants via the MIS Secure Area. Any change in TSP guidelines or switching plan must be provided to ERCOT before implementation (except for emergency). Any change in guidelines or switching plan must be provided in accordance with the NOMCR process or other ERCOT-prescribed process.

3.10.7.2 Modeling of Resources and Transmission Loads

(1) Each Resource Entity shall provide ERCOT and its interconnecting TSP with information describing each of its Generation Resources, SOGs, and Load Resources connected to the ERCOT System. All Transmission Generation Resources (TGRs), Settlement Only Transmission Generators (SOTGs), Settlement Only Transmission Self-Generators (SOTSGs), and the non-TSP owned MPTs greater than ten MVA, must be modeled to provide equivalent generation injections to the ERCOT Transmission Grid. ERCOT shall coordinate the modeling of Generation Resources, Private Use Networks, and Load Resources with their owners to ensure consistency between TSP models and ERCOT models.

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

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

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

(3) Each Resource Entity representing a Distribution Generation Resource (DGR) or Distribution Energy Storage Resource (DESR) that is registered with ERCOT pursuant to Section 16.5, Registration of a Resource Entity, shall provide ERCOT, its interconnecting DSP, and the TSP that interconnects the DSP to the transmission system with information describing each of its DGR or DESR facilities, and additional information and telemetry

as required by ERCOT and the interconnecting DSP. ERCOT shall coordinate with representatives of the Resource Entity to represent the registered DGR or DESR facilities at their appropriate Electrical Bus in the Network Operations Model.

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

[NPRR995: Replace paragraph (4) above with the following upon system implementation:]

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

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

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

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

[NPRR857: Replace paragraph (7) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

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

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

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

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

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

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

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

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

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

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

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

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

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

(e) Either:

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

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

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

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

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

3.10.7.2.1 Reporting of Demand Response

(1) ERCOT shall post on the ERCOT website by the fifth Business Day after the start of a calendar month a report of the MW of Demand response that is participating in the past month in Emergency Response Service (ERS), Ancillary Service as a Load Resource, or any pilot project permitted by subsection (k) of P.U.C. SUBST. R. 25.361, Electric Reliability Council of Texas (ERCOT). The data shall be aggregated according to the corresponding 2003 ERCOT Congestion Management Zone (CMZ). Data for participation in ERS shall be based on contracted amounts for each type of service for that calendar month. ERCOT shall set out separately MW contracted from both ERS Generators and generators that are participating by offsetting ERS Loads (with aggregated and non-aggregated ERS Generators set forth separately) and MW of ERS Loads. To the extent that a participating generator is not registered with ERCOT, information about the nameplate rating of the generator and the maximum deliverable to the ERCOT Transmission Grid or to serve native load shall be collected through the ERS contracting process. The report shall include these values for each ERS Contract Period broken down by ERS Time Period. Data for Ancillary Services shall be based on the Ancillary Service Resource Responsibility contained in the Current Operating Plan (COP) as of the start of the Adjustment Period for each Operating Day. ERCOT's posting of Ancillary Service and pilot project participation data shall include the average MW capacity by service type by hour (or by another time period, if a pilot project service is not procured hourly).

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

(1) ERCOT shall post on the ERCOT website by the fifth Business Day after the start of a calendar month a report of the MW of Demand response that is participating in the past month in Emergency Response Service (ERS), Ancillary Service as a Load Resource, or any pilot project permitted by subsection (k) of P.U.C. SUBST. R. 25.361, Electric Reliability Council of Texas (ERCOT). The data shall be aggregated according to the corresponding 2003 ERCOT Congestion Management Zone (CMZ). Data for

participation in ERS shall be based on contracted amounts for each type of service for that calendar month. ERCOT shall set out separately MW contracted from both ERS Generators and generators that are participating by offsetting ERS Loads (with aggregated and non-aggregated ERS Generators set forth separately) and MW of ERS Loads. To the extent that a participating generator is not registered with ERCOT, information about the nameplate rating of the generator and the maximum deliverable to the ERCOT Transmission Grid or to serve native load shall be collected through the ERS contracting process. The report shall include these values for each ERS Contract Period broken down by ERS Time Period. Data for Ancillary Services shall be based on the Ancillary Service Resource awards in the RTM. ERCOT's posting of Ancillary Service and pilot project participation data shall include the average MW capacity by service type by hour (or by another time period, if a pilot project service is not procured hourly).

3.10.7.2.2 Annual Demand Response Report

(1) On an annual basis, ERCOT shall work with Market Participants to produce a report summarizing aggregate customer counts and MWs enrolled in Demand response in the ERCOT Region pursuant to subsection (e)(5) of P.U.C. SUBST. R. 25.505, Reporting Requirements and the Scarcity Pricing Mechanism in the Electric Reliability Council of Texas Power Region. This report shall be posted to the ERCOT website no later than December 31 of each reporting calendar year. Technical requirements for providing information to ERCOT for the report are located in the Other Binding Document titled "Demand Response Data Definitions and Technical Specifications". ERCOT may, for purposes of this section, associate Entities; however, ERCOT shall not determine Non-Opt-In Entities (NOIEs) to be associated based on their membership in a generation and transmission cooperative or as a result of being a party to a single Load Serving Entity (LSE) registration.

(a) Retail Electric Providers (REPs) in competitive regions of ERCOT shall be ranked in descending order by their average daily consumption for summer (June – September) weekdays excluding holidays. The largest REPs that account for 98% of the total shall be required to participate in the survey for the subsequent calendar year. For purposes of assigning this participation requirement, REPs determined by ERCOT to be associated shall have their consumption aggregated prior to the ranking.

(b) NOIE Transmission and/or Distribution Service Providers (TDSPs) operating in the ERCOT region that register a summer month (June – September) 15-minute interval peak Demand greater than or equal to 100 MW, shall be required to participate in the survey the subsequent calendar year. For purposes of assigning this participation requirement, NOIEs determined by ERCOT to be associated shall have their 15-minute interval peak Demand aggregated prior to the ranking. Participation in the survey shall be the responsibility of either the NOIE TDSP or the NOIE LSE associated with that TDSP based on which entity is responsible for administering Demand response programs within the NOIE TDSP footprint.

(2) By December 31 of each year, ERCOT shall provide advance notice of participation status. To the extent that REPs discontinue participation in the ERCOT market or change associations prior to the snapshot date, ERCOT will send revised notices to REPs affected by such changes no later than August 1 of the survey year. ERCOT shall:

(a) Analyze the summer consumption for all NOIEs and REPs and determine which are required to participate in the Demand response survey for the following year;

(b) Provide advance notice, via email to the Authorized Representative, to all NOIEs and REPs regarding their participation status; and

(c) Provide a list of all REPs or NOIE TDSPs to the Authorized Representative, including all those determined by ERCOT to be associated, to which the participation status applies.

(3) By August 1 of the survey year, ERCOT shall provide official notice of the beginning of the Demand response data collection process. ERCOT shall:

(a) Issue a Market Notice to notify all REPs and NOIEs that the annual Demand response data collection process is beginning. The Market Notice shall make reference to this Protocol section, and shall reiterate specifics of the timeline for the survey process that are to be followed;

(b) Send a reminder email to the Authorized Representative for all REPs, NOIE LSEs and NOIE TDSPs of their participation status. The email shall also contain the list of all REPs or NOIE TDSPs, for which participation status applies. The list shall include all REPs or NOIE TDSPs determined by ERCOT to be associated. This list shall be updated based on any changes in associations that have occurred since the time the advance notice was issued.

(4) By August 15 of the survey year, REPs and NOIEs that are required to participate in that year's survey, and that will have Customers participating in one or more Demand response program as of the snapshot date of September 1 shall reply to ERCOT with the following:

(a) An acknowledgement of the participation requirement;

(b) An indication that they expect to have Customers participating in one or more Demand response programs on the snapshot date of September 1;

(c) A list of contact people and their email address within their organization that should receive copies of communications related to the survey from ERCOT;

(d) Specifically for REPs, an indication as to which of the methods described in the Other Binding Document titled "Demand Response Data Definitions and

Technical Specifications” the REP intends to use to submit files to and receive files from ERCOT; and

(e) Specifically for NOIEs, an indication as to whether the NOIE TDSP or the NOIE LSE is responsible for administering the Demand response programs within the NOIE TDSP area.

(5) By August 15 of the survey year, REPs and NOIEs that are required to participate in that year’s survey, and that do not plan to have any Customers participating in Demand response programs as of the snapshot date of September 1 shall reply to ERCOT indicating the lack of such participation. REPs and NOIEs that are not required to participate in that year’s survey are not required to reply to ERCOT.

(6) By October 15 of the survey year, the REPs participating in that year’s survey shall compile the required Electric Service Identifier (ESI ID) participation data in the format specified by the Other Binding Document titled “Demand Response Data Definitions and Technical Specifications”, and submit the data to ERCOT.

(7) By October 31 of the survey year, the REPs participating in that year’s survey that have reported participation in programs which entail REP-initiated deployments shall compile the required deployment event participation data in the format specified by the Other Binding Document titled “Demand Response Data Definitions and Technical Specifications”, and submit the data to ERCOT.

(8) By October 31 of the survey year, the NOIEs participating in that year’s survey shall compile the required data in the format specified by the Other Binding Document titled “Demand Response Data Definitions and Technical Specifications”, and submit the data to ERCOT.

(9) ERCOT shall validate the submitted reports, and indicate any errors and inconsistencies that require correction to the REP or NOIE, within two Business Days of the submission in the manner specified in the Other Binding Document titled “Demand Response Data Definitions and Technical Specifications”.

(10) On or before October 31 of the survey year, REPs shall address the errors and inconsistencies and submit corrected reports to ERCOT. ERCOT will notify the Authorized Representative for each REP and/or NOIE when they have achieved the required level of accuracy.

(11) On or before November 7 of the survey year, NOIEs shall address the errors and inconsistencies and submit corrected reports to ERCOT. ERCOT will notify the Authorized Representative for each REP and/or NOIE when they have achieved the required level of accuracy.

(12) Information provided by NOIEs and REPs to meet the above described reporting requirements shall be treated as Protected Information in accordance with Section 1.3, Confidentiality.

3.10.7.3 Modeling of Private Use Networks

(1) ERCOT shall create and use network models describing Private Use Networks according to the following:

(a) A Generation Entity with a Resource located within a Private Use Network shall provide data to ERCOT, for use in the Network Operations Model, for each of its individual generating unit(s) located within the Private Use Network in accordance with Section 3.3.2.1, Information to Be Provided to ERCOT, if it meets any one of the following criteria:

(i) Contains a generator greater than ten MW and is registered with the PUCT according to P.U.C. SUBST. R. 25.109, Registration of Power Generation Companies and Self-Generators, as a power generation company; or

(ii) Is part of a Private Use Network which contains more than one connection to the ERCOT Transmission Grid; or

(iii) Contains generation registered to provide Ancillary Services.

(b) A Generation Entity with an SOTSG shall provide to ERCOT annually, or more often upon change, the following information for ERCOT's use in the Network Operations Model, for each of its individual generating unit(s) located within the Private Use Network:

(i) Equipment owner(s);

(ii) Equipment operator(s);

(iii) TSP substation name connecting the Private Use Network to the ERCOT System;

(iv) At the request of ERCOT, a description of Transmission Elements within the Private Use Network that may be connected through breakers or switches;

(v) Net energy delivery metering, as required by ERCOT, to and from the Private Use Network and the ERCOT System at the POIB;

(vi) For each individual generator located within the Private Use Network, the gross capacity in MW and its reactive capability curve;

(vii) Maximum and minimum reasonability limits of the Load located within the Private Use Network;

(viii) Outage schedule for each generation unit located within the Private Use Network, updated as changes occur from the annually submitted information; and

(ix) Other interconnection data as required by ERCOT.

(c) Energy delivered to ERCOT from an SOTSG shall be settled in accordance with Section 6.6.3.2, Real-Time Energy Imbalance Payment or Charge at a Load Zone.

(d) ERCOT shall ensure the Network Operations Model properly models the physical effect of the loss of generators and Transmission Elements on the ERCOT Transmission Grid equipment loading, voltage, and stability.

(e) ERCOT may require the owner or operator of a Private Use Network to provide information to ERCOT and the TSP on Transmission Facilities located within the Private Use Network for use in the Network Operations Model if the information is required to adequately model and determine the security of the ERCOT Transmission Grid, including data to perform loop flow analysis of Private Use Networks.

(f) ERCOT shall review submittals of modeling data from owners or operators of Private Use Networks assure that it will result in correct analysis of ERCOT Transmission Grid security.

3.10.7.4 Remedial Action Schemes, Automatic Mitigation Plans and Remedial Action Plans

(1) All approved Remedial Action Schemes (RASs), Automatic Mitigation Plans (AMPs) and Remedial Action Plans (RAPs) must be defined in the Network Operations Model where practicable.

(2) Proposed new RASs, AMPs and RAPs and proposed changes to RASs, AMPs and RAPs must be submitted to ERCOT for review and approval. ERCOT shall seek input from TSPs and Resource Entities that own Transmission Facilities included in the RASs or AMPs or RAPs, and shall approve proposed new RASs, AMPs and RAPs and proposed changes to RASs, AMPs and RAPs in accordance with the process outlined in the Operating Guides. This shall include verification of the Network Operations Model. ERCOT shall provide notification to the market and post all RASs, AMPs and RAPs under consideration on the MIS Secure Area within five Business Days of receipt.

[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) Proposed new RASs, AMPs and RAPs and proposed changes to RASs, AMPs and RAPs must be submitted to ERCOT for review and approval. ERCOT shall seek input

from TSPs, DCTOs, and Resource Entities that own Transmission Facilities included in the RASs or AMPs or RAPs, and shall approve proposed new RASs, AMPs and RAPs and proposed changes to RASs, AMPs and RAPs in accordance with the process outlined in the Operating Guides. This shall include verification of the Network Operations Model. ERCOT shall provide notification to the market and post all RASs, AMPs and RAPs under consideration on the MIS Secure Area within five Business Days of receipt.

(3) ERCOT shall use a NOMCR to model approved RASs, AMPs and RAPs where practicable and include the RASs, AMPs or RAPs modeled in the Network Operations Model in the security analysis. The NOMCR shall include a detailed description of the system conditions required to implement the RASs, AMPs or RAPs. If an approved RAS, AMP, or RAP cannot be modeled, then ERCOT shall develop an alternative method for recognizing the unmodeled RAS, AMP, or RAP in its tools. Execution of RASs, AMPs or RAPs modeled in the Network Operations Model shall be included or assumed in the calculation of LMPs. ERCOT shall provide notification to the market and post on the MIS Secure Area all approved RASs, AMPs and RAPs at least two Business Days before implementation, identifying the date of implementation. The notification to the market shall state whether the approved RAP, AMP, or RAS will be modeled in the Network Operations Model. For RAPs developed in Real-Time, ERCOT shall provide notification to the market as soon as practicable.

3.10.7.5 Telemetry Requirements

(1) The telemetry provided to ERCOT necessary to support the State Estimator must meet the requirements set forth in Section 3.10.9, State Estimator Requirements.

(2) The telemetry provided to ERCOT by each TSP and QSE must be updated at a ten second or less scan rate and be provided to ERCOT at the same rate. Each TSP and QSE shall install appropriate condition detection capability to notify ERCOT of potentially incorrect data from loss of communication or scan function. Condition codes must accompany the data to indicate its quality and whether the data has been measured within the scan rate requirement. Also, ERCOT shall analyze data received for possible loss of updates. Similarly, ERCOT shall provide condition detection capability on loss of telemetry links with the TSP and QSE. ERCOT shall represent data condition codes from each TSP and QSE in a consistent manner for all applicable ERCOT applications.

[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 telemetry provided to ERCOT by each TSP, QSE, or DCTO must be updated at a ten second or less scan rate and be provided to ERCOT at the same rate. Each TSP, DCTO, and QSE shall install appropriate condition detection capability to notify ERCOT of potentially incorrect data from loss of communication or scan function. Condition codes must accompany the data to indicate its quality and whether the data has been measured within the scan rate requirement. Also, ERCOT shall analyze data received for possible loss of updates. Similarly, ERCOT shall provide condition detection capability on loss of telemetry links with the TSP, DCTO, and QSE. ERCOT shall represent data condition codes from each TSP, DCTO, and QSE in a consistent manner for all applicable ERCOT applications.

(3) Each TSP and QSE shall use fully redundant ICCP links between its control center systems and ERCOT systems such that any single element of the communication system can fail and:

(a) For server failures, complete information must be re-established within five minutes by automatic failover to alternate server(s); and

(b) For all other failures, complete information must continue to flow between the TSP's, QSE's, and ERCOT's control centers with updates of all data continuing at a 30 second or less scan rate.

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

(3) Each TSP, DCTO, and QSE shall use fully redundant ICCP links between its control center systems and ERCOT systems such that any single element of the communication system can fail and:

(a) For server failures, complete information must be re-established within five minutes by automatic failover to alternate server(s); and

(b) For all other failures, complete information must continue to flow between the TSP's, DCTO's, QSE's, and ERCOT's control centers with updates of all data continuing at a 30 second or less scan rate.

(4) When ERCOT identifies a reliability concern, a deficiency in system observability, or a deficiency in measurement to support the representation of Model Loads, and that concern or deficiency is not due to any inadequacy of the State Estimator program,

additional telemetry may be requested as described in Section 3.10.7.5.9, ERCOT Requests for Telemetry.

3.10.7.5.1 Continuous Telemetry of the Status of Breakers and Switches

(1) Each TSP and QSE shall be responsible for providing telemetry, as described in this subsection, to ERCOT on the status of all breakers and switches it owns or its Resource owns, respectively, used to switch any Transmission Element or Load modeled by ERCOT.

(2) Each TSP and QSE is not required to install telemetry on individual breakers and switches it owns or its Resource Entity owns, respectively, where the telemetered status shown to ERCOT is current and free from ambiguous changes in state caused by the TSP or Resource Entity switching operations and TSP or Resource Entity personnel.

(3) Each TSP, Resource Entity, or QSE shall update the status of any breaker or switch it owns or is responsible for through manual entries, if necessary, to communicate the actual current state of the device to ERCOT, except if the change in state is expected to return to the prior state within one minute.

(4) If in the sole opinion of ERCOT, the manual updates of the TSP or QSE have been unsuccessful in maintaining the accuracy required to support State Estimator performance to a TAC-approved predefined standard as described in Section 3.10.9, State Estimator Requirements, ERCOT may request that the TSP or QSE install complete telemetry from the breaker or switch it owns or its Resource Entity owns, respectively, to the TSP or QSE, and then to ERCOT.

(a) In making the determination to request installation of additional telemetry from a breaker or switch, ERCOT shall consider the economic implications of inaccurate representation of Model Loads in LMP results versus the cost to remedy.

(b) If the TSP or QSE disputes the request for additional telemetry on individual breakers and switches it owns or its Resource Entity owns, respectively, it may appeal the request pursuant to Section 3.10.7.5.9, ERCOT Requests for Telemetry.

[NPRR857: Replace paragraphs (1) through (4) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(1) Each TSP, DCTO, and QSE shall provide telemetry, as described in this subsection, to ERCOT on the status of all breakers and switches it owns or its Resource Entity owns, respectively used to switch any Transmission Element or Load modeled by ERCOT.

(2) Each TSP, DCTO, and QSE is not required to install telemetry on individual breakers and switches it owns or its Resource Entity owns, respectively, where the telemetered status shown to ERCOT is current and free from ambiguous changes in state caused by the TSP, DCTO, or QSE switching operations and TSP, DCTO, or QSE personnel.

(3) Each TSP, DCTO, and QSE shall update the status of any breaker or switch it owns or its Resource Entity owns, respectively, through manual entries, if necessary, to communicate the actual current state of the device to ERCOT, except if the change in state is expected to return to the prior state within one minute.

(4) If in the sole opinion of ERCOT, the manual updates of the TSP, DCTO, or QSE have been unsuccessful in maintaining the accuracy required to support State Estimator performance to a TAC-approved predefined standard as described in Section 3.10.9, State Estimator Requirements, ERCOT may request that the TSP, DCTO, or QSE install complete telemetry from the breaker or switch it owns or its Resource Entity owns, respectively, to the TSP, DCTO, or QSE, and then to ERCOT.

(a) In making the determination to request installation of additional telemetry from a breaker or switch, ERCOT shall consider the economic implications of inaccurate representation of Model Loads in LMP results versus the cost to remedy.

(b) If the TSP or associated QSE disputes the request for additional telemetry it owns or its Resource Entity owns, respectively, it may appeal the request pursuant to Section 3.10.7.5.9, ERCOT Requests for Telemetry.

(5) ERCOT shall measure TSP and QSE performance in providing accurate data that do not include ambiguous changes in state and shall report the performance metrics on the MIS Secure Area on a monthly basis.

[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) ERCOT shall measure TSP, DCTO, and QSE performance in providing accurate data that do not include ambiguous changes in state and shall report the performance metrics on the MIS Secure Area on a monthly basis.

(6) Unless there is an Emergency Condition, TSPs and QSEs must obtain approval from ERCOT to purposely open a breaker or switch unless that breaker or switch is shown in a Planned Outage in the Outage Scheduler, or the device will return to its previous state within 60 minutes, or the device is a generator output circuit breaker. Also, TSPs and QSEs must obtain approval from ERCOT before closing any breaker or switch, except in response to a Forced Outage, or an emergency, or the device will return to its previous state within 60 minutes, or the device is a generator output circuit breaker.

[NPRR857: Replace paragraph (6) 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:]

(6) Unless there is an Emergency Condition, TSPs, DCTOs, and QSEs must obtain approval from ERCOT to purposely open a breaker or switch unless that breaker or switch is shown in a Planned Outage in the Outage Scheduler, or the device will return to its previous state within 60 minutes, or the device is a generator output circuit breaker. Also, TSPs, DCTOs, and QSEs must obtain approval from ERCOT before closing any breaker or switch, except in response to a Forced Outage, or an emergency, or the device will return to its previous state within 60 minutes, or the device is a generator output circuit breaker.

(7) ERCOT shall monitor the data condition codes of all breakers and switches showing loss of communication or scan function in the Network Operations Model. When the telemetry of breakers and switches is lost, ERCOT shall use the last known state of the device for security analysis as updated by the Outage Scheduler and through verbal communication with the TSP or QSE. ERCOT's systems must identify probable errors in switch or breaker status and ERCOT shall act to resolve or correct such errors in a timely manner as described in Section 6, Adjustment Period and Real-Time Operations.

[NPRR857: Replace paragraph (7) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(7) ERCOT shall monitor the data condition codes of all breakers and switches showing loss of communication or scan function in the Network Operations Model. When the telemetry of breakers and switches is lost, ERCOT shall use the last known state of the device for security analysis as updated by the Outage Scheduler and through verbal

communication with the TSP, DCTO, or QSE. ERCOT's systems must identify probable errors in switch or breaker status and ERCOT shall act to resolve or correct such errors in a timely manner as described in Section 6, Adjustment Period and Real-Time Operations.

(8) ERCOT shall establish a system that provides alarms to ERCOT Operators when there is a change in status of any monitored transmission breaker or switch, and an indication of whether the device change of status was planned in the Outage Scheduler. ERCOT Operators shall monitor any changes in status not only for reliability of operations, but also for accuracy and impact on the operation of the SCED functions and subsequent potential for calculation of inaccurate LMPs.

(9) Each QSE that represents a Split Generation Resource, with metering according to Section 3.8, Special Considerations for Split Generation Meters, Combined Cycle Generation Resources, Quick Start Generation Resources, Hydro Generation Resources, Energy Storage Resources, Distribution Generation Resources, and Distribution Energy Storage Resources, shall provide ERCOT with telemetry of the actual generator breakers and switches continuously providing ERCOT with the status of the individual Split Generation Resource.

3.10.7.5.2 Continuous Telemetry of the Real-Time Measurements of Bus Load, Voltages, Tap Position, and Flows

(1) Each TSP and QSE shall provide telemetry of voltages, flows, and Loads on any modeled Transmission Element it owns or its Resource Entity owns, respectively, to the extent such may be required to estimate all transmission Load withdrawals and generation injections to and from the ERCOT Transmission Grid using the State Estimator and as needed to meet the State Estimator requirements set forth in Section 3.10.9, State Estimator Requirements, with consideration given to the economic implications of inaccurate LMP results versus the cost to remedy.

[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, DCTO, and QSE shall provide telemetry of voltages, flows, and Loads on any modeled Transmission Element it owns or its Resource Entity owns, respectively, to the extent such may be required to estimate all transmission Load withdrawals and generation injections to and from the ERCOT Transmission Grid using the State Estimator and as needed to meet the State Estimator requirements set forth in Section

3.10.9, State Estimator Requirements, with consideration given to the economic implications of inaccurate LMP results versus the cost to remedy.

(2) Each QSE that represents a Split Generation Resource, with metering according to Section 3.8, Special Considerations for Split Generation Meters, Combined Cycle Generation Resources, Quick Start Generation Resources, Hydro Generation Resources, Energy Storage Resources, and Distribution Generation Resources, and Distribution Energy Storage Resources, shall provide ERCOT with telemetry of the actual equivalent generator injection of its Split Generation Resource and the Master QSE shall provide telemetry in accordance with Section 6.5.5.2, Operational Data Requirements, on a total Generation Resource basis. ERCOT shall calculate the sum of each QSE's telemetry on a Split Generation Resource and compare the sum to the telemetry for the total Generation Resource. ERCOT shall notify each QSE representing a Split Generation Resource of any errors in telemetry detected by the State Estimator.

(3) Each TSP and QSE shall provide telemetered measurements at a periodicity of ten seconds on modeled Transmission Elements it owns or its Resource Entity owns, respectively, to ensure State Estimator observability of any monitored voltage and power flow between their associated transmission breakers to the extent such can be shown to be needed to meet the State Estimator requirements set forth in Section 3.10.9. On monitored non-Load substations, ERCOT may request additional telemetry in accordance with Section 3.10.7.5.10, ERCOT Requests for Redundant Telemetry.

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

(3) Each TSP, DCTO, and QSE shall provide telemetered measurements at a periodicity of ten seconds on modeled Transmission Elements it owns or its Resource Entity owns, respectively, to ensure State Estimator observability of any monitored voltage and power flow between their associated transmission breakers to the extent such can be shown to be needed to meet the State Estimator requirements set forth in Section 3.10.9. On monitored non-Load substations, ERCOT may request additional telemetry in accordance with Section 3.10.7.5.10, ERCOT Requests for Redundant Telemetry.

(4) The accuracy of the State Estimator is critical to successful market operations. For this reason it is a critical objective for ERCOT to maintain reasonable and accurate results of the State Estimator. ERCOT shall use all reasonable efforts to achieve that objective, including the provision of legitimate constraints used in calculating LMPs.

(5) Each TSP, QSE and ERCOT shall develop a continuously operated program to maintain telemetry of all Transmission Element measurements to provide accurate State Estimator results as outlined in Section 3.10.9. For any location where there is a connection of multiple, measured, Transmission Elements, ERCOT shall have an automated process to detect and notify ERCOT System operators if the residual sum of all telemetered measurements is more than:

(a) 5% of the largest line Normal Rating at the State Estimator Bus; or

(b) Five MW, whichever is greater.

If a location chronically fails this test, ERCOT shall notify the applicable TSP or QSE and suggest actions that the TSP or QSE could take to correct the failure. Within 30 days, the TSP or QSE shall take the actions necessary to correct the failure or provide ERCOT with a detailed plan with a projected time frame to correct the failure. ERCOT shall post a notice on the MIS Secure Area of any State Estimator Buses not meeting the State Estimator requirements set forth in Section 3.10.9, including a list of all measurements and the residual errors on a monthly basis.

[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) Each TSP, DCTO, QSE, and ERCOT shall develop a continuously operated program to maintain telemetry of all Transmission Element measurements to provide accurate State Estimator results as outlined in Section 3.10.9. For any location where there is a connection of multiple, measured, Transmission Elements, ERCOT shall have an automated process to detect and notify ERCOT System operators if the residual sum of all telemetered measurements is more than:

(a) 5% of the largest line Normal Rating at the State Estimator Bus; or

(b) Five MW, whichever is greater.

If a location chronically fails this test, ERCOT shall notify the applicable TSP, DCTO, or QSE and suggest actions that the TSP, DCTO, or QSE could take to correct the failure. Within 30 days, the TSP, DCTO, or QSE shall take the actions necessary to correct the failure or provide ERCOT with a detailed plan with a projected time frame to correct the failure. ERCOT shall post a notice on the MIS Secure Area of any State Estimator Buses not meeting the State Estimator requirements set forth in Section 3.10.9, including a list of all measurements and the residual errors on a monthly basis.

(6) ERCOT shall implement a study mode version of the State Estimator with special tools designed for troubleshooting and tuning purposes that can be used independently of any other ERCOT process that is dependent on the Real-Time State Estimator. ERCOT shall implement a process to recognize inaccurate State Estimator results and shall create and implement alternative Real-Time LMP calculation processes for use when inaccurate results are detected. ERCOT must be guided in this by Section 3.10.9.

(7) ERCOT shall establish a system to provide overload and over/under limit alarming on all Transmission Elements monitored as constraints in the LMP models.

(8) Each TSP shall designate which telemetered measurement of the POIB voltage shall be utilized to determine compliance with Voltage Set Point instructions, and then update the designation as necessary in the Network Operations Model by submitting a NOMCR. Each TSP shall telemeter this POI kV bus measurement to ERCOT. If the TSP cannot provide a kV bus measurement at the POI, the TSP may propose an alternate location subject to ERCOT approval.

[NPRR1098: Insert paragraph (9) below upon system implementation and satisfying the following conditions: (1) Southern Cross Transmission LLC (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 Transmission Service Provider (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:]

(9) Each TO designated by a DCTO operating a DC Tie meeting the applicability requirements of paragraph (1) of Section 3.15.4, Direct Current Tie Owner and Direct Current Tie Operator (DCTO) Responsibilities Related to Voltage Support, shall designate which telemetered measurement of the POIB voltage shall be utilized to determine compliance with target voltage instructions, and then update the designation as necessary in the Network Operations Model by submitting a NOMCR. Each TO shall telemeter this POI kV bus measurement to ERCOT via ICCP and the DCTO via telemetry. If the TO cannot provide a kV bus measurement at the POI, the TO may propose an alternate location subject to ERCOT approval.

3.10.7.5.3 Required Telemetry of Voltage and Power Flow

(1) QSEs, Resource Entities and TSPs as indicated in each subsection below shall provide power operation data to ERCOT, including, but not limited to:

(a) Real-Time generation data from QSEs;

(b) Planned and Forced Outage information from QSEs;

(c) Network data from TSPs and QSEs , including:

(i) Breaker and line switch status of all ERCOT Transmission Grid devices;

(ii) Line flow MW and MVAr;

(iii) Breaker and switch status connected to any Resource;

(iv) Transmission Facility voltages; and

(v) Transformer MW, MVAr and tap;

(d) Real-Time generation and Load Resource meter data from QSEs;

(e) Real-Time generation meter splitting signal from QSEs;

(f) Transmission Facility Planned and Forced Outage information from TSPs;

(g) Network transmission data (model and constraints) from TSPs; and

(h) Resource modeling data, including any Resource owned transmission equipment data from Resource entity; and

(i) Dynamic schedules from QSEs.

(2) Real-Time data will be provided to ERCOT at the same scan rate as the TSP, Resource Entity, or QSE obtains the data from telemetry unless ERCOT requests a slower rate.

3.10.7.5.4 General Telemetry Performance Criteria

(1) The following criteria will apply to telemetry provided to ERCOT. Performance is posted on the MIS Secure Area in accordance with Nodal Operating Guide Section 9, Monitoring Programs:

(a) Each TSP shall maintain the sum of flows into any telemetered bus it owns or is responsible for less than the greater of five MW or 5% of the largest normal line rating at each bus.

(b) Each TSP and QSE shall provide data to ERCOT that meets the following availability:

(i) 92% of all telemetry provided to ERCOT must achieve a quarterly availability of 80%. Availability shall be measured based on end-to-end connectivity of the communications path and the passing of Real-Time data with a Valid, Manual, or Calculated quality code at the scheduled periodicity. Quality codes are defined in Section 3.10.7.5.8.1, Data Quality Codes.

(ii) TSPs shall make reasonable efforts to obtain data from Customers associated with new Customer-owned substations to meet this requirement or obtain agreement from ERCOT that these Customers have entered into arrangements with ERCOT to provide this data to ERCOT. If the data cannot be obtained under either of these methods, ERCOT shall report such case to the IMM.

(c) Exceptions to the general telemetry performance criteria may be made, at ERCOT's sole discretion, for data points not significant in the solution of the State Estimator or required for the reliable operation on the ERCOT Transmission Grid. Examples of such data points include but are not limited to:

(i) A substation with no more than two transmission lines and less than ten MW of peak Load;

(ii) Connection of Loads along a continuous, non-branching circuit that may be combined for telemetry purposes; and

(iii) Substations connected radially to the ERCOT Transmission Grid.

(d) During a Force Majeure Event, ERCOT may suspend requirements until normal operations have resumed.

3.10.7.5.5 Supplemental Telemetry Performance Criteria

(1) ERCOT shall identify specific MW/MVAr telemetry pairs, not exceeding 10% of the Transmission Elements within the ERCOT System, and the 20 station voltage points that are most important to reliability, system observability or support of State Estimator performance, or are of a commercial market concern.

(2) The important telemetry points identified pursuant to this Section must meet more stringent criteria for accuracy and availability where specifically addressed. ERCOT shall review this list annually. ERCOT shall publish the list of important telemetry points quarterly on the MIS Secure Area.

(3) ERCOT shall use the following criteria to identify the important telemetry points:

(a) Loss of a telemetry point that results in the inability of ERCOT to monitor loading on a transmission line operated at 345 kV or above.

(b) Loss of a telemetry point that results in the inability of ERCOT to monitor loading on a 345/138 kV autotransformer.

(c) Loss of a telemetry point that results in the inability of ERCOT to monitor the loading on Transmission Facilities designated as important to transmission reliability by ERCOT.

(d) Telemetry necessary to monitor Transmission Elements identified as causing 80% of all congestion cost in the year for which the most recent data is available.

(e) Telemetry necessary to monitor the bus voltages at the 20 most important station voltage points.

(4) Each TSP and QSE shall provide data to ERCOT such that 92% of the important telemetry points identified achieve a quarterly availability of 90%. Availability shall be measured based on end-to-end connectivity of the communications path and the passing of Real-Time data with Valid, Manual, or Calculated quality codes at the scheduled periodicity. Quality codes are defined in Section 3.10.7.5.8.1, Data Quality Codes.

3.10.7.5.6 TSP/QSE Telemetry Restoration

(1) Telemetered data shall be provided continuously. Real-Time data restoration shall comply with Nodal Operating Guide Sections 7.3.3, Data from WAN Participants to ERCOT, and 7.3.4, Resolving Real-Time Data Issues that affect ERCOT Network Security Analysis.

(2) Some data may be more essential to the State Estimator solution. ERCOT shall inform the TSP or QSE if, in the sole opinion of ERCOT, a data item is essential and needs to be repaired as quickly as possible. QSEs and TSPs shall make repair procedures and records available to ERCOT upon request. When ERCOT notifies a data provider that a data element is providing telemetry data inconsistent with surrounding measurements, the provider shall, within 30 days, do one of the following:

(a) Calibrate or repair the failing equipment;

(b) Request an outage to schedule calibration or repair of the failing equipment;

(c) Provide ERCOT with a plan to re-calibrate or repair the equipment in a reasonable time frame; or

(d) Provide ERCOT with engineering analysis proving the data element is providing accuracy within its specifications.

(3) Before ERCOT requests review or re-calibration of a problem piece of equipment, it shall discuss the problem with the data provider to attempt to arrive at a consensus decision on the most appropriate action.

3.10.7.5.7 Calibration, Quality Checking, and Testing

(1) It is the responsibility of the equipment owner to insure that calibration, testing, and other routine maintenance of equipment is done on a timely basis, and that accuracy meets or exceeds the requirements specified in this Section 3.10.7.5, Telemetry Requirements, for both the overall system and for individual equipment where detailed herein. Coordination with ERCOT of outages required for these activities is also the responsibility of the owner.

3.10.7.5.8 Inter-Control Center Communications Protocol (ICCP) Links

3.10.7.5.8.1 Data Quality Codes

(1) Market Participants shall provide documentation to ERCOT describing their native system quality codes and defining the conversion of their quality codes into the ERCOT-defined quality codes.

(2) Statuses and analogs telemetered to ERCOT shall be identified with the following quality codes:

(a) Valid – Represents an analog or status the TSP or QSE considers valid.

(b) Manual – Represents an analog or status entered manually at the Market Participant (i.e., not received from the field electronically).

(c) Calculated – Represents an analog point that the TSP or QSE calculates.

(d) Suspect – Represents an analog or status of which the TSP or QSE is unsure of the validity

(e) Invalid – Represents an analog or status that the Market Participant has identified as out of reasonability limits.

(f) Com_fail – Informs ERCOT that due to communications failure, the analog or status provided ERCOT is not current.

3.10.7.5.8.2 Reliability of ICCP Associations

(1) Each Market Participant using ICCP associations must achieve a monthly availability of 98%, excluding approved Planned Outages. Availability shall be measured based on end-to-end connectivity of the communications path and the passing of configured data at the scheduled periodicity. To meet the 98% monthly availability, each Market Participant should establish a process to coordinate downtime for ICCP associations and database maintenance. High availability configuration as allowed by the ERCOT Nodal ICCP Communication Handbook should be treated as a single association to achieve this availability measure.

3.10.7.5.9 ERCOT Requests for Telemetry

(1) ERCOT is required to protect Transmission Facilities operated at 60 kV or above from damage. To do this, ERCOT may request that additional telemetry be installed, while attempting to minimize adding equipment to as few locations as practicable.

(2) ERCOT may request additional telemetry when it determines that network observability or the measurement redundancy is not adequate to produce acceptable State Estimator results.

(3) Prior to making a request for additional telemetry, ERCOT shall provide evidence supporting a congestion or reliability problem requiring additional observability and define expected improvements in ERCOT System observability needed. If the request is for telemetry additions at more than one location, ERCOT shall prioritize the requested additions.

(4) No later than 60 days after receipt of a request for additional telemetry, the TSP or QSE shall:

(a) Accept ERCOT's request for additional telemetry and notify ERCOT of the implementation schedule, which shall be no later than 18 months following the receipt of the request for additional telemetry;

(b) Provide an alternative proposal to ERCOT, for implementation no later than 18 months following the receipt of the request for additional telemetry, that meets the requirements described by ERCOT;

(c) Propose a normal topology change by changing normal status of switch(es) in the area that would eliminate the security violations that are ERCOT's concern;

(d) Indicate that the requested telemetry point is at a location where the TSP or QSE does not have the authority to install the requested telemetry. For points on privately owned facilities connected to the ERCOT Transmission Grid, an attempt will be made to facilitate ERCOT's telemetry request;

(e) Provide ERCOT an analysis of the cost to comply with the request, so that, ERCOT can perform a cost justification with respect to the LMP market; or

(f) If the TSP or QSE disagrees with the request, the TSP or QSE may request that ERCOT withdraw its request for additional telemetry.

[NPRR979: Replace paragraph (4) above with the following upon system implementation of NPRR857:]

(4) No later than 60 days after receipt of a request for additional telemetry, the TSP, DCTO, or QSE shall:

(a) Accept ERCOT's request for additional telemetry and notify ERCOT of the implementation schedule, which shall be no later than 18 months following the receipt of the request for additional telemetry;

(b) Provide an alternative proposal to ERCOT, for implementation no later than 18 months following the receipt of the request for additional telemetry, that meets the requirements described by ERCOT;

(c) Propose a normal topology change by changing normal status of switch(es) in the area that would eliminate the security violations that are ERCOT's concern;

(d) Indicate that the requested telemetry point is at a location where the TSP, DCTO, or QSE does not have the authority to install the requested telemetry. For points on privately owned facilities connected to the ERCOT Transmission Grid, an attempt will be made to facilitate ERCOT's telemetry request;

(e) Provide ERCOT an analysis of the cost to comply with the request, so that, ERCOT can perform a cost justification with respect to the LMP market; or

(f) If the TSP, DCTO, or QSE disagrees with the request, the TSP, DCTO, or QSE may request that ERCOT withdraw its request for additional telemetry.

(5) If ERCOT rejects an alternative proposal pursuant to paragraph (4)(b), (c), or (f) above, the TSP or QSE may appeal the original request to TAC within 30 days of receiving notice of ERCOT's rejection. If, after receiving an appeal, TAC does not resolve the appeal within 65 days, the TSP or QSE may present its appeal to the ERCOT Board. Notwithstanding the foregoing, a TSP or QSE is not required to provide telemetry measurements from a location not owned by that TSP or QSE if the location owner does not grant access to the TSP or QSE for the purpose of obtaining such measurements. ERCOT shall report such cases to the IMM.

[NPRR979: Replace paragraph (5) above with the following upon system implementation of NPRR857:]

(5) If ERCOT rejects an alternative proposal pursuant to paragraph (4)(b), (c), or (f) above, the TSP, DCTO, or QSE may appeal the original request to TAC within 30 days of receiving notice of ERCOT's rejection. If, after receiving an appeal, TAC does not resolve the appeal within 65 days, the TSP, DCTO, or QSE may present its appeal to the ERCOT Board. Notwithstanding the foregoing, a TSP, DCTO, or QSE is not required to provide telemetry measurements from a location not owned by that TSP, DCTO, or QSE if the location owner does not grant access to the TSP, DCTO, or QSE for the purpose of obtaining such measurements. ERCOT shall report such cases to the IMM.

3.10.7.5.10 ERCOT Requests for Redundant Telemetry

(1) ERCOT shall maintain redundancy on monitored non-Load substations.

(2) ERCOT shall identify new telemetry required to maintain N-1 observability on monitored non-Load substations. The following conditions shall be used to determine what additional telemetry is required:

(a) Inability of ERCOT to monitor loading on a transmission line operated at 345 kV or above.

(b) Inability of ERCOT to monitor loading on a 345/138 kV autotransformer.

(c) Inability of ERCOT to monitor loading on Transmission Facilities designated as important to transmission reliability by ERCOT.

(3) ERCOT may request additional MW, MVAr and voltage telemetry to make these measurements redundant. In this request, ERCOT shall identify these measurements, and the contingency/overload condition and the unit dispatch that makes this a concern. If the request is for telemetry at multiple locations, ERCOT shall prioritize the requested additions.

(4) Except as provided in paragraph (5) below, no later than 60 days after receipt of a request for additional telemetry, a TSP or QSE shall:

(a) Accept ERCOT's request for additional telemetry and notify ERCOT of the implementation schedule, which shall be no later than 18 months following the receipt of the request for additional telemetry; or

(b) Propose an alternative solution that will serve the same purpose as the ERCOT identified telemetry additions, with a proposed implementation no later than 18 months following the receipt of the request for additional telemetry;

(5) In cases where the request is based on the availability rate of an existing telemetry point, no later than 30 days after receipt of a request for additional telemetry, the TSP or QSE shall:

(a) Provide a plan to improve the availability rate of the identified telemetry to meet the requirements of paragraph (1)(b)(i) of Section 3.10.7.5.4, General Telemetry Performance Criteria, and paragraph (3) of Section 3.10.7.5.5, Supplemental Telemetry Performance Criteria;

(b) Provide documentation for why the improvements set forth in paragraph (a) above cannot be accomplished;

(c) Identify and propose a schedule of equipment installations or maintenance to be completed no later 18 months following the receipt of the request for additional telemetry that would, as a result, change the classification of the Transmission Element identified by ERCOT; or

(d) Indicate that the facility for which telemetry is being requested is not owned or covered by an agreement that allows the requested party to install the additional telemetry.

(6) If ERCOT rejects an alternative solution proposed pursuant to paragraph (4) or (5) above, the TSP or QSE may appeal the original request to TAC within 30 days of receiving notice of ERCOT's rejection. If, after receiving an appeal, TAC does not resolve the appeal within 65 days, the TSP or QSE may present its appeal to the ERCOT Board. Notwithstanding the foregoing, a TSP or QSE is not required to provide telemetry measurements from a location not owned by that TSP or QSE if the location owner does not grant access to the TSP or QSE for the purpose of obtaining such measurements. ERCOT shall report such cases to the IMM.

3.10.7.6 Use of Generic Transmission Constraints and Generic Transmission Limits

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

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

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

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

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

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

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

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

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

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

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

3.10.7.7 DC Tie Limits

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

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

[NPRR825: Replace Section 3.10.7.7 above with the following upon system implementation:]

3.10.7.7 DC Tie Advisory Limits

(1) Every hour, ERCOT shall post DC Tie advisory limits for each hour of the next 48 hours to the MIS Secure Area. ERCOT may update these limits as system conditions change. Any updated DC Tie advisory limits shall be posted to the MIS Secure Area as soon as practicable.

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

3.10.8 Dynamic Ratings

(1) ERCOT shall use Dynamic Ratings, where available, in the Network Operations Model and the CRR Network Models.

(2) ERCOT shall use Dynamic Ratings in place of the Normal Rating, Emergency Rating and 15-Minute Rating as applicable as provided under paragraphs (a) or (b) below for Transmission Elements established in the Network Operations Model.

(a) A TSP may provide Dynamic Ratings via ICCP for implementation in the next Operating Hour. ERCOT shall use the Dynamic Ratings in its Supervisory Control and Data Acquisition (SCADA) alarming, Real Time Security Analysis, and SCED process. In addition, the TSP shall provide ERCOT with a table of equipment rating versus temperature for use in operational planning studies.

(b) Each TSP may alternatively elect to provide ERCOT with a table of equipment rating versus temperature and a temperature value in Real-Time for each Weather Zone in which the Transmission Element is located. ERCOT shall apply the table of temperature and rating relationships and ERCOT's current temperature measurements to determine the rating of each such designated piece of equipment for each Operating Hour. ERCOT shall use the TSP-provided table in operational planning studies.

(3) Each Operating Hour, ERCOT shall post on the MIS Secure Area updated Dynamic Ratings adjusted for the current temperature.

(4) ERCOT may request that a TSP submit temperature-adjusted ratings on Transmission Elements that ERCOT identifies as contributing to significant congestion costs. Each TSP shall provide the additional ratings within two months of such a request using one of the two mechanisms for supplying temperature-adjusted ratings identified above. Ratings for Transmission Elements operated by multiple TSPs must be supplied by each TSP that has control. ERCOT shall use the most limiting rating and report the circumstance to the IMM.

3.10.8.1 Dynamic Ratings Delivered via ICCP

(1) The TSP shall supply the following, via ICCP, updated at least every ten minutes:

(a) Normal Rating; and

(b) Optionally Emergency Rating and/or 15-Minute Rating (required when Emergency Rating is provided).

(2) ERCOT shall link each provided line rating with the ERCOT Network Operations Model and implement the ratings for the next Operating Hour. ERCOT shall use the Dynamic Ratings in its SCADA alarming, real-time Security Analysis, and SCED process. When the telemetry is not operational, ERCOT shall use a temperature appropriate for current conditions, and employ the required Dynamic Rating lookup table to determine the appropriate rating.

3.10.8.2 Dynamic Ratings Delivered via Static Table and Telemetered Temperature

(1) ERCOT shall define a set of tables implementing the dynamic characteristics provided by the TSP(s) and as applicable, Resource Entity(s), of selected transmission lines, including:

(a) Line ID;

(b) From station;

(c) To station;

(d) Weather Zone(s);

(e) TSP(s) and Resource Entity(s); and

(f) Each of the three ratings: Normal Rating, Emergency Rating, and 15-Minute Rating.

(2) If a TSP is providing a current temperature for each applicable Weather Zone through SCADA telemetry then ERCOT shall determine the appropriate rating based upon the telemetered temperature, and adjust the Normal Rating, Emergency Rating, and 15-Minute Rating within five minutes of receipt for the next Operating Hour. ERCOT shall

use the Dynamic Ratings in its SCADA alarming, real-time Security Analysis, and SCED process.

3.10.8.3 Dynamic Rating Network Operations Model Change Requests

(1) ERCOT shall use the NOMCR process by which TSPs provide electronically to ERCOT the dynamic rating table described in Section 3.10.8.2, Dynamic Ratings Delivered via Static Table and Telemetered Temperature.

3.10.8.4 ERCOT Responsibilities Related to Dynamic Ratings

(1) ERCOT shall provide a system to accept and implement Dynamic Ratings or temperatures to be applied to rating tables for each hour in the Day-Ahead and in the Operating Hour. ERCOT shall also:

(a) Provide software and processes that allow secure access for TSPs and Market Participants and that maintains a log of data provided and the actions of the TSP and ERCOT, to implement the Dynamic Ratings as described above;

(b) Use Dynamic Ratings for alarming, compliance with ERCOT and NERC requirements, and SCED purposes in both Real-Time operations and operational planning;

(c) Approve or reject the new Dynamic Rating request within 24 hours of receipt;

(d) Post Dynamic Ratings approved by ERCOT for each planned production load of the Network Operations Model on the MIS Secure Area. The posting will include the Transmission Element name, approved thermal rating limits, and the planned effective date; and

(e) Implement the approved Dynamic Rating automatically within 24 hours of approval.

(2) ERCOT shall provide a system to implement Dynamic Ratings and to obtain monthly expected ambient air temperatures to be applied to rating tables for the CRR Network Models. Temperatures applied to the rating tables shall be determined using the same method as described in item (3)(f) of Section 7.5.5.4, Simultaneous Feasibility Test. Transmission Elements that have Dynamic Ratings implemented in the Network Operations Model must have Dynamic Ratings in the CRR Network Models.

(3) ERCOT shall identify additional Transmission Elements that have a high probability of providing significant added economic efficiency to the ERCOT market through Dynamic Rating and request such Dynamic Ratings from the associated TSP. ERCOT shall post annually the list of the Transmission Elements and identify if the TSP has agreed to provide the rating on the MIS Secure Area.

3.10.8.5 Transmission Service Provider Responsibilities Related to Dynamic Ratings

(1) Each TSP shall:

(a) Provide ERCOT with tables of ratings for different ambient temperatures for Transmission Elements, as requested by ERCOT.

(b) Submit within two months a temperature adjusted rating table when a request is received from ERCOT unless multiple requests are made by ERCOT within the two-month period or unusual circumstances prevent the request from being accommodated in a timely fashion. Such circumstances must be explained to ERCOT in writing and must be posted by ERCOT on the MIS Secure Area within five Business Days of receipt.

(c) Provide Real-Time temperatures for each Weather Zone in which the TSP has existing dynamically rated transmission equipment, or alternatively provide rating updates for each temperature-adjusted line rating updated at least once every ten minutes.

3.10.9 State Estimator Requirements

(1) The appropriate TAC subcommittee shall coordinate with Market Participants to ensure a common understanding of the level of State Estimator performance required to enable LMP calculation and address the State Estimator's ability to detect, correct, or otherwise accommodate communications system failures, failed data points, stale data condition codes, and missing or inaccurate measurements to the extent these capabilities contribute to LMP accuracy and State Estimator performance or as needed to meet reliability requirements.

3.10.9.1 Considerations for State Estimator Requirements

(1) In maintaining the State Estimator requirements, the following may be considered:

(a) Desired confidence levels of State Estimator results;

(b) Measurement requirements to estimate power injections and withdrawals at transmission voltage Electrical Buses defined in the SCED transmission model, which may provide for variations in criteria based on:

(i) The number of Transmission Elements connected to a given transmission voltage Electrical Bus;

(ii) The peak demand of the Load connected to a transmission voltage Electrical Bus;

(iii) The total of Resource capacity connected to a transmission voltage Electrical Bus;

(iv) The nominal transmission voltage level of an Electrical Bus;

(v) The number of Electrical Buses with injections or withdrawals along a circuit between currently monitored transmission voltage Electrical Bus;

(vi) Connection of Loads along a continuous, non-branching circuit that may be combined for modeling purposes;

(vii) The quantity of Load at an Electrical Bus that may have its connection to the transmission system automatically transferred to an Electrical Bus other than the one to which it is normally connected (rollover operation);

(vii) Electrical proximity to more than one Resource Node;

(viii) Degree or quality of continued observability following the loss of telemetry measurements resulting from a common mode failure of telemetry-related equipment (*i.e.*, an N-1 telemetry condition); and

(ix) Other parameters or circumstances, as appropriate;

(c) Sensitivity of State Estimator results with respect to variations in input parameters;

(d) Reasonable safeguards to assure State Estimator results are calculated on a non-discriminatory basis; and

(e) Other parameters as deemed appropriate.

3.10.9.2 State Estimator Data

(1) ERCOT uses a State Estimator to produce Load flow base cases, which are used to analyze the reliability of the ERCOT Transmission Grid. Accurate and redundant telemetry and an accurate transmission power system model are required by the State Estimator in order to produce an optimal estimation of the transmission power system state. State Estimator results are used in contingency analysis, congestion management, and other network analysis Real-Time sequence functions.

3.10.9.3 Telemetry Status and Analog Measurements Data

(1) Good telemetry status and analog measurements data for the transmission power system together with an accurate model of the ERCOT System are processed by the State Estimator to provide an optimal estimate of the ERCOT System state at a given point in time while filtering minor measurement errors and detecting gross errors. The quality and availability of telemetry provided to ERCOT is important to the performance of the ERCOT State Estimator.

(2) Telemetry is not needed at every node of the ERCOT System to arrive at a good estimate of the ERCOT System's state. State Estimator performance must meet the performance requirements set forth in Section 3.10.9.4, State Estimator Performance Requirements, unless otherwise provided for in the Operating Guides.

(3) Beyond general telemetry performance criteria there are more stringent criteria needed at locations where state estimates are critically important, including, but not limited to, locations where reliability, security, and market impacts are of heightened concern.

3.10.9.4 State Estimator Performance Requirements

(1) The State Estimator shall converge 98% of runs during a one month period.

(2) For MW flows on Transmission Elements identified by ERCOT as causing 80% of congestion costs in the latest year for which data is available, the residual difference between State Estimator results and power flow results shall be less than 3% of the associated element Emergency Rating on at least 95% of samples measured in a one month period.

(3) For Transmission Elements identified by ERCOT as causing 80% of all congestion costs in the latest year for which data is available, the difference between the telemetry value (MW) and the State Estimator value (MW) shall be less than 3% of the associated element Emergency Rating on at least 95% of samples measured in a one month period.

(4) For the 20 most important station voltage points, as designated by ERCOT and approved by ROS, the telemetered voltage minus State Estimator voltage shall be within 2% of the telemetered voltage measurement for at least 95% of samples measured during a one month period.

(5) For all Transmission Elements 100 kV and above, the difference between the State Estimator solution (MW) and the SCADA measurement will be less than ten MW or 10% of the associated Emergency Rating (whichever is greater) on 99.5% of samples measured during a one month period. ERCOT shall report all equipment failing this test to the associated TSP who shall repair such equipment no later than ten days following detection by ERCOT.

(6) ERCOT shall post the State Estimator performance requirements contained in this Section on the MIS Secure Area.

3.10.9.5 ERCOT Directives

(1) ERCOT shall work with the TSP or QSE to resolve telemetry and/or model problems in accordance with telemetry requirements prior to directing additional equipment.

(2) In the event of failure to meet the requirements in paragraphs (2) or (3) of Section 3.10.9.4, State Estimator Performance Requirements, ERCOT may direct additional

telemetry to be installed on elements contributing most to 80% of congestion costs for the latest year for which data is available. If the TSP or QSE disputes the request for additional telemetry, pursuant to paragraph (4) of Section 3.10.7.5.9, ERCOT Requests for Telemetry, the TSP or QSE may provide an alternative proposal.

(3) ERCOT shall enforce the requirements of paragraph (5) of Section 3.10.7.5.2, Continuous Telemetry of the Real-Time Measurements of Bus Load, Voltages, Tap Position, and Flows, by alarming any sum of flow around a bus that is more than (a) 5% of the largest normal line rating connected to the bus, or (b) five MW, whichever is greater, and requesting that the applicable TSP or QSE correct the failure.

(4) ERCOT shall consider the quality codes sent by the data provider in determining how confidence factors are assigned for the data to be used in the State Estimator. Valid and manual quality codes as defined in Section 3.10.7.5.8.1, Data Quality Codes, shall be considered as good quality. Quality codes sent as not good quality shall be considered at a lower confidence.

3.10.9.6 Telemetry and State Estimator Performance Monitoring

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

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

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

3.11 Transmission Planning

3.11.1 Overview

(1) Project endorsement through the ERCOT regional planning process is intended to support, to the extent applicable, a finding by the Public Utility Commission of Texas (PUCT) that a project is necessary for the service, accommodation, convenience, or

safety of the public within the meaning of Public Utility Regulatory Act, TEX. UTIL. CODE ANN. § 37.056 (Vernon 1998 and Supp. 2007) (PURA) and P.U.C. SUBST. R. 25.101, Certification Criteria.

3.11.2 Planning Criteria

(1) ERCOT and Transmission Service Providers (TSPs) shall evaluate the need for transmission system improvements and shall evaluate the relative value of alternative improvements based on established technical and economic criteria.

(2) The technical reliability criteria are established by the Planning Guide, Operating Guides, and the North American Electric Reliability Corporation (NERC) Reliability Standards. ERCOT and TSPs shall strongly endeavor to meet these criteria, identify current and future violations thereof and initiate solutions necessary to ensure continual compliance.

(3) ERCOT shall attempt to meet these reliability criteria as economically as possible and shall actively study the need for economic projects to meet this goal.

(4) For economic projects, the net economic benefit of a proposed project, or set of projects, will be assessed over the project's life based on the net societal benefit that is reasonably expected to accrue from the project. The project will be recommended if it is reasonably expected to result in positive net societal benefits.

(5) To determine the societal benefit of a proposed project, the revenue requirement of the capital cost of the project is compared to the expected savings in system production costs resulting from the project over the expected life of the project. Indirect benefits and costs associated with the project should be considered as well, where appropriate. The current set of financial assumptions upon which the revenue requirement calculations is based will be reviewed annually, updated as necessary by ERCOT, and posted on the Market Information System (MIS) Secure Area. The expected production costs are based on a chronological simulation of the security-constrained unit commitment and economic dispatch of the generators connected to the ERCOT Transmission Grid to serve the expected ERCOT System Load over the planning horizon. This market simulation is intended to provide a reasonable representation of how the ERCOT System is expected to be operated over the simulated time period. From a practical standpoint, it is not feasible to perform this production cost simulation for the entire 30 to 40 year expected life of the project. Therefore, the production costs are projected over the period for which a simulation is feasible and a qualitative assessment is made of whether the factors driving the production cost savings due to the project can reasonably be expected to continue. If so, the levelized ERCOT-wide annual production cost savings over the period for which the simulation is feasible is calculated and compared to the first year annual revenue requirement of the transmission project. If this production cost savings equals or exceeds this annual revenue requirement for the project, the project is economic from a societal perspective and will be recommended.

(6) Other indicators based on analyses of ERCOT System operations may be considered as appropriate in the determination of benefits. In order for such an alternate indicator to be

considered, the costs must be reasonably expected to be on-going and be adequately quantifiable and unavoidable given the physical limitation of the transmission system. These alternate indicators include:

(a) Reliability Unit Commitment (RUC) Settlement for unit operations;

(b) Visible ERCOT market indicators such as clearing prices of Congestion Revenue Rights (CRRs); and

(c) Actual Locational Marginal Prices (LMPs) and observed congestion.

3.11.3 Regional Planning Group

(1) ERCOT shall lead and facilitate a Regional Planning Group (RPG) to consider and review proposed projects to address transmission constraints and other ERCOT System needs. The RPG will be a non-voting, consensus-based organization focused on identifying needs, identifying potential solutions, communicating varying viewpoints and reviewing analyses related to the ERCOT Transmission Grid in the planning horizon. Participation in the RPG is required of all TSPs and is open to all Market Participants, consumers, other stakeholders, and PUCT Staff.

3.11.4 Regional Planning Group Project Review Process

3.11.4.1 Project Submission

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

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

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

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

3.11.4.2 Project Comment Process

(1) ERCOT shall conduct a comment process which is open to the stakeholders for all proposed Tier 1, 2 and 3 projects. The proposer of the project will have a reasonable period of time, as established by ERCOT, to answer questions and respond to comments submitted during this process. The Planning Guide provides details of this process.

3.11.4.3 Categorization of Proposed Transmission Projects

(1) ERCOT classifies all proposed transmission projects into one of four categories (or Tiers). Each Tier is defined so that projects with a similar cost and impact on reliability and the ERCOT market are grouped into the same Tier. For Tier classification, the total estimated cost of the project shall be used which includes costs borne by another party.

(a) A project shall be classified as Tier 1 if the estimated capital cost is greater than or equal to $100,000,000, unless the project is considered to be a neutral project pursuant to paragraph (f) below.

(b) A project shall be classified as Tier 2 if the estimated capital cost is less than $100,000,000 and a Certificate of Convenience and Necessity (CCN) is required, unless the project is considered to be a neutral project pursuant to paragraph (f) below.

(c) A project shall be classified as Tier 3 if any of the following are true:

(i) The estimated capital cost is less than $100,000,000 and greater than or equal to $25,000,000 and a CCN is not required, unless the project is considered to be a neutral project pursuant to paragraph (f) below; or

(ii) The estimated capital cost is less than $25,000,000, a CCN is not required, and the project includes 345 kV circuit reconductor of more than one mile, additional 345/138 kV autotransformer capacity, or a new 345 kV substation, unless the project is considered to be a neutral project pursuant to paragraph (f) below.

(d) A project with an estimated capital cost greater than or equal to $25,000,000 that is proposed for the purpose of replacing aged infrastructure or storm hardening shall be processed as a Tier 3 project and shall be reclassified as a Tier 4, neutral project upon ERCOT's determination that any concerns, questions or objections raised during the comment process have been resolved satisfactorily.

(e) A project shall be classified as Tier 4 if it does not meet the requirements to be classified as Tier 1, 2, or 3 or if it is considered a neutral project pursuant to paragraph (f) below.

(f) A project shall be considered a neutral project if it consists entirely of:

(i) The addition of or upgrades to radial transmission circuits;

(ii) The addition of equipment that does not affect the transfer capability of a circuit;

(iii) Repair and replacement-in-kind projects;

(iv) Transmission Facilities needed to connect a new Generation Resource, Energy Storage Resource (ESR), or Settlement Only Generator (SOG) to a new or existing substation on the existing ERCOT Transmission Grid, including the substation;

(v) The addition of static reactive devices;

(vi) A project to serve a new Load, unless such project would create a new transmission circuit connection between two stations (other than looping an existing circuit into the new Load-serving station);

(vii) Replacement of failed equipment, even if it results in a ratings and/or impedance change; or

(viii) Equipment upgrades resulting in only ratings changes.

(2) ERCOT may use its reasonable judgment to increase the level of review of a proposed project (e.g., from Tier 3 to Tier 2) from that which would be strictly indicated by these criteria, based on stakeholder comments, ERCOT analysis or the system impacts of the project.

(a) A project with an estimated capital cost greater than or equal to $50,000,000 that requires a CCN shall be reclassified and processed as a Tier 1 project upon request by a Market Participant during the comment period per Planning Guide Section 3.1.5, Regional Planning Group Comment Process.

(3) Any project that would be built by an Entity that is exempt (e.g., a Municipally Owned Utility (MOU)) from getting a CCN for transmission projects but would require a CCN if it were to be built by a regulated Entity will be treated as if the project would require a CCN for the purpose of defining the Tier of the project.

(4) If during the course of ERCOT's independent review of a project, the project scope changes, ERCOT may reclassify the project into the appropriate Tier.

3.11.4.4 Processing of Tier 4 Projects

(1) For any project classified in Tier 4, ERCOT will not solicit comments from RPG, conduct any independent review, or provide any endorsement for the project.

3.11.4.5 Processing of Tier 3 Projects

(1) ERCOT shall accept a Tier 3 project if no concerns, questions or objections are provided during the project comment process.

(2) If reasonable ERCOT or stakeholder concerns about a Tier 3 project cannot be resolved during the time period allotted by ERCOT, the project may be processed as a Tier 2 project, unless ERCOT assesses that reasonable progress is being made toward resolving these concerns.

3.11.4.6 Processing of Tier 2 Projects

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

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

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

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

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

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

3.11.4.7 Processing of Tier 1 Projects

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

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

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

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

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

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

(2) Tier 1 projects require ERCOT Board endorsement.

3.11.4.8 Determine Designated Providers of Transmission Additions

(1) Upon completion of an independent review, ERCOT shall determine the designated TSPs for any recommended transmission additions. The designated TSP for a recommended transmission addition will be the TSP that owns the end point(s) of the recommended transmission addition. The designated TSP can agree to provide the recommended transmission addition or delegate the responsibility to another TSP. If different TSPs own the two end points of a recommended transmission addition, ERCOT will designate them as co-providers of the recommended transmission addition, and they can decide between themselves what parts of the recommended transmission addition they will each provide. If they cannot agree, ERCOT will determine their responsibility following a meeting with the parties. If a designated TSP agrees to provide a recommended transmission addition but does not diligently pursue the recommended transmission addition (during the time frame before a CCN is filed, if required) in a manner that will meet the required in-service date, then upon concurrence of the ERCOT Board, ERCOT will solicit interest from TSPs through the RPG and will designate an alternate TSP.

3.11.4.9 Regional Planning Group Acceptance and ERCOT Endorsement

(1) For Tier 3 projects, successful resolution of all comments received from ERCOT and stakeholders during the project comment process will result in RPG acceptance of the proposed project. An RPG acceptance letter shall be sent to the TSP(s) for the project, the project submitter (if different from the TSP(s)), and posted on the MIS Secure Area. For Tier 2 projects, ERCOT's recommendation as a result of its independent review of the proposed project will constitute ERCOT endorsement of the need for a project except as noted in paragraph (4) below. For Tier 1 projects, ERCOT's endorsement is obtained upon affirmative vote of the ERCOT Board except as noted in paragraph (4) below. An ERCOT endorsement letter shall be sent to the TSP(s) for the project, the project submitter (if different from the TSP(s)), and the PUCT, and posted on the MIS Secure Area upon receipt of ERCOT's endorsement for Tier 1 and Tier 2 projects except as noted in paragraph (4) below.

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

(3) If the asserted need for a Tier 1 or Tier 2 project is based on a service request from a specific customer, a TSP may submit the project for RPG Project Review prior to that customer signing a letter agreement for the financial security of the necessary upgrades. However, ERCOT shall not issue an independent review recommending such a project until the customer signs any required letter agreement, provides any required notice to proceed, and provides the full amount of any financial security required for the upgrades needed to serve that customer.

(4) If a TSP asserts a need for a proposed Tier 1 or Tier 2 project based in part or in whole on its own planning criteria, then ERCOT's independent review shall also consider whether a reliability need exists under the TSP's criteria. If ERCOT identifies a reliability need under the TSP's criteria, then ERCOT shall recommend a project that would address that need as well as any reliability need identified under NERC or ERCOT criteria, but shall explicitly state in the independent review report that ERCOT has assumed the TSP's criteria are valid and that an assessment of the validity of the TSP's criteria is beyond the scope of ERCOT's responsibility. ERCOT or the ERCOT Board may provide a qualified endorsement of such a project if ERCOT determines that it is justified in part under ERCOT or NERC criteria, as described in paragraph (1) above. However, neither ERCOT nor the ERCOT Board shall endorse a project that is determined to be needed solely to meet a TSP's criteria.

3.11.4.10 Modifications to ERCOT Endorsed Projects

(1) If the TSP for an ERCOT-endorsed project determines a need to make a significant change to the facilities included in the project (such as the line endpoint(s), number of circuits, voltage level, decrease in rating or similar major aspect of the project), the TSP shall notify ERCOT of the details of that change prior to filing a CCN application, if required, or prior to beginning the final design of the project if no CCN application is required. If ERCOT concurs that the proposed change is significant, the change shall be processed as a Tier 3 project, unless ERCOT determines the project should more appropriately be processed in another Tier.

(2) For economic-driven projects, if a TSP determines that the estimated project cost has increased by more than 10% over the cost described in ERCOT's endorsement, the TSP shall notify RPG prior to filing a CCN application if required, or prior to beginning the final design of the project if no CCN application is required, and provide an explanation

for the cost increase. For comparison purposes, the cost of the route that best meets PUCT criteria will be used.

3.11.4.11 Customer or Resource Entity Funded Transmission Projects

(1) If an affected TSP elects to pursue a Customer or Resource Entity funded transmission project that would have been classified as a Tier 1, Tier 2, or Tier 3 project for RPG Project Review, the TSP(s) shall conduct a reliability impact assessment of the proposed transmission project and shall submit a report summarizing the results of the reliability impact assessment for RPG Project Review. Such projects shall be processed according to their Tier classification and shall be reclassified as a Tier 4, neutral project upon ERCOT's determination that any concerns, questions or objections raised during the comment process have been resolved satisfactorily.

(2) ERCOT's independent review of a Tier 1 or Tier 2 Customer or Resource Entity funded transmission project will be limited to assessing the reliability and congestion impact of the proposed project and submitting a report summarizing the results and findings to RPG for review and discussion. ERCOT will not endorse the project and will not present the project to the ERCOT Board. However, ERCOT may recommend the project not be implemented or recommend changes to the project scope if, in ERCOT's sole discretion, the project negatively impacts the reliability or congestion of the ERCOT System.

(3) Customer or Resource Entity funded Tier 4 projects do not need to go through this review process.

3.11.5 Transmission Service Provider and Distribution Service Provider Access to Interval Data

(1) ERCOT shall provide specific interval data for Load and generation to TSPs and/or Distribution Service Providers (DSPs), upon request, in accordance with confidentiality as defined in Section 1.3, Confidentiality.

(a) The TSP's and/or DSP's request for interval data shall identify the reason for requesting the information in regards to impact to the planning process (e.g. build power flow cases, conduct a specific study, etc.).

(b) ERCOT shall evaluate the TSP and/or DSP request and validate reasons provided.

(c) Upon ERCOT validation of the TSP and/or DSP request, the data provided shall include meter data measured at points of injection and points of delivery which will measurably impact the TSP's and/or DSP's planning and operations as determined by ERCOT (e.g., determination of the TSP's and/or DSP's system Load or power flows).

(d) If ERCOT determines that the request is invalid and denies it, ERCOT shall provide the reasoning for denying the request.

3.11.6 Generation Interconnection Process

(1) The generation interconnection process facilitates the interconnection of new generation units in the ERCOT Region by assessing the transmission upgrades necessary for new generating units to operate reliably. The process to study interconnecting new generation or modifying an existing generation interconnection to the ERCOT Transmission Grid is covered in the Planning Guide. The generation interconnection study process primarily addresses the direct connection of generation Facilities to the ERCOT Transmission Grid and directly-related projects. Projects that are identified through this process and are regional in nature may be reviewed through the RPG Project Review process upon recommendation by the TSP or ERCOT, subject to the confidentiality provisions in Section 1.3, Confidentiality.

(2) ERCOT shall perform an independent economic analysis of the Transmission Facilities needed to connect a new Generation Resource, ESR, or SOG to a new or existing substation on the existing ERCOT Transmission Grid, including the substation, that are identified through this process that are expected to cost more than $25,000,000. This economic analysis is performed only for informational purposes; as such, no ERCOT endorsement will be provided. The results of the economic analysis shall be included in the interconnection study posting.

(3) Additional upgrades to the ERCOT Transmission Grid that might be cost-effective as a result of new or modified generation may be initiated by any stakeholder through the RPG Project Review procedure described in Section 3.11.4, Regional Planning Group Project Review Process, at the appropriate time, subject to the confidentiality provisions of the generation interconnection procedure.

3.12 Load Forecasting

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

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

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

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

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

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

3.12.1 Seven-Day Load Forecast

(1) ERCOT shall use the Seven-Day Load Forecast to predict hourly Loads for the next 168 hours based on current weather forecast parameters within each Weather Zone. Preparation for Day-Ahead Operations requires an accurate forecast of the Loads for which generation capacity must be secured. The Seven-Day Load Forecast must have a "self-training" mode that allows ERCOT to review historic Load data and provide the ability to retrain the Seven-Day Load Forecast algorithm.

[NPRR975: Insert paragraphs (a) and (b) below upon system implementation:]

(a) ERCOT will use a variety of Load forecast models and will select the Load forecast model that best fits the expected conditions for each hour of the next 168 hours as the Seven-Day Load Forecast for that hour and may update this selection as expected conditions change.

(b) If the selected forecast used at the time of the Day-Ahead Reliability Unit Commitment (DRUC) for the peak Demand hour of any of the next seven days is above or below the average of the forecast models for that hour by the greater of 2000 MW or 4% of the average of the forecast models for that hour, ERCOT shall produce and post to the ERCOT website an explanation of why the outlier Load forecast model was selected for that hour.

(2) The inputs for the Seven-Day Load Forecast are as follows:

(a) Hourly forecasted weather parameters for the weather stations within the Weather Zones, which are updated at least once per hour; and

(b) Training information based on historic hourly integrated Weather Zone Loads.

(3) ERCOT shall review the forecast suggested by Seven-Day Load Forecast and shall use its judgment, if necessary, to modify the result prior to implementation in the Ancillary Service Capacity Monitor, Day-Ahead Reliability Unit Commitment (DRUC), Hour-Ahead Reliability Unit Commitment (HRUC), and Resource adequacy reporting.

3.12.2 Study Areas

(1) ERCOT shall develop and use Study Areas for Load forecasting and study purposes, and will provide the Load forecast data to the market. A list of Study Areas shall be available on the ERCOT website.

3.12.3 Seven-Day Study Area Load Forecast

(1) ERCOT shall develop and post hourly on the ERCOT website a "Seven-Day Study Area Load Forecast" to predict the hourly Loads for the next 168 hours based on current weather forecast parameters within each Study Area.

(a) The forecast referenced in paragraph (1) above will not affect the values within the "Seven-Day Load Forecast" by Weather Zone and/or Forecast Zone.

3.13 Renewable Production Potential Forecasts

(1) ERCOT shall produce forecasts of Renewable Production Potential (RPP) for Wind-powered Generation Resources (WGRs) and PhotoVoltaic Generation Resources (PVGRs) to be used as an input into the Day-Ahead Reliability Unit Commitment (DRUC) and Hour-Ahead Reliability Unit Commitment (HRUC). ERCOT shall produce the forecasts using information provided by WGR/PVGR Entities, meteorological information, and Supervisory Control and Data Acquisition (SCADA). WGR and PVGR Entities shall install telemetry at their respective Resources and transmit the ERCOT-specified site-specific meteorological information to ERCOT. WGR and PVGR Entities shall also provide detailed equipment status at the WGR/PVGR facility as specified by ERCOT to support the RPP forecast. ERCOT shall post forecasts for each WGR and PVGR to the Qualified Scheduling Entities (QSEs) representing WGRs and/or PVGRs on the Market Information System (MIS) Certified Area. QSEs shall use the ERCOT-provided forecasts for WGRs/PVGRs throughout the Day-Ahead and Operating Day for applicable markets and Reliability Unit Commitments (RUCs). Similar requirements for run-of-the-river hydro must be developed as needed.

[NPRR1029: Replace paragraph (1) above with the following upon system implementation:]

(1) ERCOT shall produce forecasts of Renewable Production Potential (RPP) for Wind-powered Generation Resources (WGRs), PhotoVoltaic Generation Resources

(PVGRs), and the intermittent renewable generation component of each DC-Coupled Resource to be used as an input into the Day-Ahead Reliability Unit Commitment (DRUC) and Hour-Ahead Reliability Unit Commitment (HRUC). ERCOT shall produce the forecasts using information provided by WGRs, PVGRs, and DC-Coupled Resources; meteorological information; and Supervisory Control and Data Acquisition (SCADA). A Resource Entity with a WGR, PVGR, or DC-Coupled Resource shall install equipment to enable telemetry of site-specific meteorological information that ERCOT determines is necessary to produce the RPP forecast, and the Resource Entity's QSE shall telemeter such information and Resource status information to ERCOT. ERCOT shall post forecasts for each WGR and PVGR and for the intermittent renewable generation component of each DC-Coupled Resource to the MIS Certified Area for the Qualified Scheduling Entity (QSE) representing that WGR, PVGR, or DC-Coupled Resource. QSEs shall use the ERCOT-provided forecasts for WGRs, PVGRs, and DC-Coupled Resources in the Day-Ahead and throughout the Operating Day for applicable markets and Reliability Unit Commitments (RUCs). Similar requirements for run-of-the-river hydro must be developed as needed.

(2) ERCOT shall develop cost-effective tools or services to forecast energy production from Intermittent Renewable Resources (IRRs) with technical assistance from QSEs scheduling IRRs. ERCOT shall use its best efforts to develop accurate and unbiased forecasts, as limited by the availability of relevant explanatory data. ERCOT shall post on the MIS Secure Area objective criteria and thresholds for unbiased, accurate forecasts within five Business Days of change.

[NPRR1029: Replace paragraph (2) above with the following upon system implementation:]

(2) ERCOT shall develop cost-effective tools or services to forecast energy production from Intermittent Renewable Resources (IRRs) and from the intermittent renewable generation component of each DC-Coupled Resource with technical assistance from QSEs representing such Resources. ERCOT shall use its best efforts to develop accurate and unbiased forecasts, as limited by the availability of relevant explanatory data. ERCOT shall post on the MIS Secure Area objective criteria and thresholds for unbiased, accurate forecasts within five Business Days of change.

3.14 Contracts for Reliability Resources and Emergency Response Service Resources

(1) ERCOT shall procure Reliability Must-Run (RMR) Service, Black Start Service (BSS) or Emergency Response Service (ERS) through Agreements.

[NPRR885: Replace paragraph (1) above with the following upon system implementation:]

(1) ERCOT shall procure Reliability Must-Run (RMR) Service, Must-Run Alternative (MRA) Service, Black Start Service (BSS), or Emergency Response Service (ERS) through Agreements.

3.14.1 Reliability Must Run

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

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

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

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

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

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

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

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

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

(e) ERCOT may execute RMR Agreements for no less than one month and no more than one year, with one exception. ERCOT may execute an RMR Agreement for a term longer than 12 months if the Resource Entity must make a significant capital expenditure to meet environmental regulations or to ensure availability to continue operating the RMR Unit so as to make an RMR Agreement in excess of 12 months appropriate, in ERCOT's opinion. The term of a multi-year RMR Agreement must take into account the appropriate RMR exit strategy discussed in Section 3.14.1.4, Exit Strategy from an RMR Agreement. In the event ERCOT chooses to contract for an RMR Unit for longer than one year, ERCOT shall annually re-evaluate the need for the RMR Unit under the criteria set forth in paragraph (b) above. If ERCOT determines the RMR Unit is no longer needed, ERCOT shall enter into exit negotiations with the contract signatories to attempt to exit the contract early. However, ERCOT shall not enter into such negotiations until a Market Notice is issued providing the anticipated RMR exit time frame. The RMR standard Agreement is included in Section 22, Attachment B, Standard Form Reliability Must-Run Agreement. ERCOT shall post each RMR Agreement in its entirety, including amendments or modifications thereto, within five Business Days of execution on the MIS Secure Area.

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

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

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

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

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

(i) Participating in the bilateral energy market;

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

(iii) Providing of Ancillary Service to any Entity.

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

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

3.14.1.1 Notification of Suspension of Operations

(1) Except for the occurrence of a Forced Outage, a Resource Entity must notify ERCOT in writing no less than 150 days prior to the date on which the Resource Entity intends to cease or suspend operation of a Generation Resource for a period of greater than 180 days. If a Generation Resource is to be mothballed on a seasonal basis, the Resource Entity must notify ERCOT in writing no less than 90 days prior to the suspension date and identify its Seasonal Operation Period.

(2) The Resource Entity shall submit a completed Part I and Part II of the NSO (found in Section 22, Attachment E, Notification of Suspension of Operations). The Resource Entity may also complete Part III of the NSO and submit it along with Parts I and II, or may wait to submit Part III up to ten days after ERCOT makes a determination that the proposed suspension of the Generation Resource would result in a performance deficiency for which the Generation Resource has a material impact. Part I of the NSO must include the attestation of an officer of the Resource Entity that the Generation Resource is uneconomic to remain in service as currently designated and will be unavailable for Dispatch by ERCOT for a period specified in the NSO.

(3) A Resource Entity ceasing or suspending operations as a result of a Forced Outage lasting greater than 180 days shall notify ERCOT as soon as practicable by submitting an NSO. If an NSO is submitted for a Generation Resource that is suspending operations for greater than 180 days due to a Forced Outage but is not indefinitely or permanently ceasing operations, then:

(a) The Generation Resource will not be evaluated for RMR status;

(b) The NSO will not be posted on the MIS, except that information contained in the NSO may be included in reports in accordance with Section 3.2.6.2.2, Total Capacity Estimate; and

(c) ERCOT will not issue a Market Notice.

(4) At least 60 days before the expiration of an existing RMR Agreement, the Resource Entity may apply to renew the RMR Agreement by submitting a new NSO (including both Part I and Part II). Upon receipt of such a renewal request, ERCOT shall update and post to the MIS Secure Area studies as set forth in Section 3.14.1, Reliability Must Run, within 15 Business Days.

3.14.1.2 ERCOT Evaluation Process

(1) Except as provided in paragraph (3) of Section 3.14.1.1, Notification of Suspension of Operations, upon receipt of an NSO under Section 3.14.1.1 ERCOT shall post the NSO on the MIS Secure Area and shall post all existing relevant studies and data and provide a Market Notice of the NSO and posting of the studies and data.

(2) Within 21 days after receiving the NSO described in paragraph (1) above, unless otherwise notified by ERCOT that a shorter comment period is required, Market Participants may submit comments to ERCOT on whether the Generation Resource(s) referenced in the NSO is necessary to support ERCOT System reliability or should qualify for a multi-year RMR Agreement. ERCOT shall consider and post all submitted comments on the MIS Secure Area.

(3) ERCOT shall conduct a reliability analysis of the need for any Generation Resource(s) with a summer Seasonal net max sustainable rating greater than or equal to 20 MW to support ERCOT System reliability. For Generation Resource(s) with a summer Seasonal net max sustainable rating less than 20 MW, ERCOT may conduct a reliability analysis if deemed appropriate by ERCOT following consultation with affected Transmission Service Provider(s) (TSP(s)).

(a) ERCOT shall use a Load forecast consistent with current Regional Transmission Plan assumptions and methodologies for the appropriate season(s). If additional new Generation Resources meet the criteria in Planning Guide Section 6.9, Addition of Proposed Generation to the Planning Models, ERCOT shall include those additional Generation Resources with the appropriate seasonal ratings.

(b) If the NSO indicates that the Generation Resource(s) will decommission or suspend operation, or in the case of a Forced Outage, has permanently ceased operation, ERCOT, in its sole discretion, may perform transmission reliability analysis over a planning horizon as defined by the available base cases but not to exceed two years.

(c) For purposes of the reliability analysis, ERCOT shall use the following criteria to identify a performance deficiency that is materially impacted by the Generation Resource:

(i) Without the Generation Resource, there are one or more Transmission Facilities loaded above their Normal Rating under pre-contingency conditions.

(ii) Without the Generation Resource, there is any instability or cascading for any of the following conditions:

(A) Pre-contingency;

(B) Normal system conditions followed by the contingency loss of a generating unit, transmission circuit, common tower outage, transformer, shunt device, or flexible alternating current transmission system (FACTS) device;

(C) Unavailability of a generating unit, followed by Manual System Adjustments, followed by the contingency loss of a generating unit, transmission circuit, common tower outage, transformer, shunt device, or FACTS device; or

(D) Unavailability of a 345/138 kV transformer, followed by Manual System Adjustments, followed by the contingency loss of a generating unit, transmission circuit, common tower outage, transformer, shunt device, or FACTS device.

(iii) Without the Generation Resource, there are one or more Transmission Facilities loaded above 110% of the Emergency Rating under normal system conditions followed by the contingency loss of a generating unit, transmission circuit, common tower outage, transformer, shunt device, or FACTS device.

(iv) For paragraphs (i) through (iii) above, the Generation Resource will only be deemed to have a material impact on a performance deficiency that is caused by a thermal overload(s) if the Generation Resource has a more than 2% unloading Shift Factor on the Transmission Facility(s) that is overloaded and more than 5% unloading impact on the Transmission Facility(s) that is overloaded. For purposes herein, an unloading impact is a measure of a reduction in flow on a Transmission Facility as a percent of its Rating due to a unit injection of power from the Generation Resource.

(v) ERCOT may, in its sole discretion, deviate from the above criteria in order to maintain ERCOT System reliability. However, ERCOT shall present its reasons for deviating from the above criteria to the Technical Advisory Committee (TAC) and ERCOT Board.

(d) ERCOT, in consultation with affected TSP(s), may rely upon the results of past planning studies to determine if the Generation Resource is necessary to support ERCOT System reliability. The past planning studies must have used the same or more restrictive reliability criteria than the criteria described in paragraph (c) above.

(e) Additionally, ERCOT shall conduct any other analysis (e.g., operations studies) as required and shall post all study data and results and all analyses and its determination on the MIS Secure Area and issue a Market Notice of its determination.

(4) Within 30 days after receiving the NSO, ERCOT shall issue a Market Notice indicating the status of the reliability analysis referenced in paragraph (3) above. The Market Notice will indicate one of the following:

(a) ERCOT has completed its reliability analysis and the Generation Resource is not required to support ERCOT System reliability;

(b) ERCOT has completed its reliability analysis and the analysis identifies a performance deficiency for which the Generation Resource has a material impact; or

(c) ERCOT has not completed its reliability analysis and will need additional time to complete the assessment.

(5) Within 60 days after receiving Part I and Part II of the NSO, ERCOT shall complete its reliability analysis described in paragraph (3) above and shall issue a Market Notice describing the results of its reliability analysis if the results were not provided in the Market Notice issued under paragraph (4) above. If ERCOT determines that the Generation Resource is not needed to support ERCOT System reliability, then the Generation Resource may cease or suspend operations according to the schedule in its NSO, unless ERCOT in its sole discretion permits the Generation Resource to suspend operations at an earlier date, and ERCOT shall note this in the Market Notice.

(6) Within ten days after a determination by ERCOT that the proposed suspension of the Generation Resource would result in a performance deficiency on which the Generation Resource has a material impact, as described in this Section, ERCOT shall issue a Request for Proposal (RFP) for Must-Run Alternatives (MRAs). ERCOT shall include in the RFP reasonably available information that would enable potential MRAs to assess the feasibility of submitting a proposal to provide a more cost-effective alternative to the Generation Resource, including any known minimum technical requirements and/or operational characteristics required to eliminate the identified performance deficiency. The MRA RFP shall specify the expected number of hours that an MRA would be needed during the contract period, and the hours of the day, by season, that the MRA would be required to be available. ERCOT shall establish an RFP response schedule such that responses can be evaluated prior to 150 days after submittal of the NSO.

(7) Within ten days after a determination by ERCOT that the proposed suspension of the Generation Resource would result in a performance deficiency on which the Generation Resource has a material impact, as described in this Section, the Resource Entity shall, if it has not already done so, complete and submit to ERCOT Part III of the NSO (Section 22, Attachment E, Notification of Suspension of Operations). ERCOT shall post the Part III information on the MIS Secure Area. Concurrently, the Generation Resource shall submit an initial estimated budget used in the calculation of the proposed Standby Cost and RMR fuel adder, prepared in accordance with Section 3.14.1.11, Budgeting Eligible Costs, and Section 3.14.1.20, Budgeting Fuel Costs, to ERCOT. On or before the 11th day after the determination or the receipt of Part III of the NSO, whichever comes first, ERCOT and the Resource Entity shall begin good faith negotiations on an RMR Agreement. These negotiations shall include the budgeting process for Eligible Costs and for fuel costs as detailed in Section 3.14.1.11 and Section 3.14.1.20.

(8) ERCOT shall issue a Market Notice on the status of the RMR Unit or MRA, including the start date, duration of the RMR or MRA Agreement, the Standby Cost ($/Hour) as applicable, and the amount of MW under contract, within 24 hours of signing an RMR or MRA Agreement with a Resource Entity.

(9) Except in cases where the Generation Resource is to be mothballed on a seasonal basis, if, after 150 days following ERCOT's receipt of Part I and Part II of the NSO, ERCOT has neither notified the Resource Entity that the continued operation of the Generation Resource is not required nor obtained ERCOT Board approval to enter into an RMR or MRA Agreement, then the Resource Entity may file a complaint with the Public Utility Commission of Texas (PUCT) under subsection (e)(1) of P.U.C. SUBST. R. 25.502, Pricing Safeguards in Markets Operated by the Electric Reliability Council of Texas. If the Generation Resource is to be mothballed on a seasonal basis, then the Resource Entity may file such a complaint with the PUCT under subsection (e)(1) of P.U.C. SUBST. R. 25.502 if ERCOT has neither notified the Resource Entity that the continued operation of the Generation Resource is not required nor obtained ERCOT Board approval to enter into an RMR Agreement within 90 days following ERCOT's receipt of Part I and Part II of the NSO.

(10) If the ERCOT Board approves entering into an RMR Agreement but ERCOT and the Resource Entity have not both executed the RMR Agreement by the date on which the Resource Entity intends to cease or suspend operation of the Generation Resource, then the Resource Entity shall maintain that Generation Resource(s) so that it is available for Reliability Unit Commitment (RUC) commitment until no longer required to do so under subsection (e)(2) of P.U.C. SUBST. R. 25.502. This paragraph does not apply to a Generation Resource that suspended operations due to a Forced Outage.

3.14.1.2.1 ERCOT Evaluation of Seasonal Mothball Status

(1) ERCOT shall evaluate requests to place Generation Resources on a seasonal mothball status pursuant to the guidelines provided in Section 3.14.1.2, ERCOT Evaluation Process, except as stated below.

(2) Within 30 days after receiving the NSO described in Section 3.14.1.1, Notification of Suspension of Operations, ERCOT shall issue a Market Notice indicating the status of the reliability analysis described in paragraph (3) of Section 3.14.1.2. The Market Notice will indicate one of the following:

(a) ERCOT has completed its reliability analysis and the Generation Resource is not required to support ERCOT System reliability during the portion of the year when the Generation Resource would be unavailable;

(b) ERCOT has completed its reliability analysis and the analysis identifies a performance deficiency for which the Generation Resource has a material impact during the portion of the year when the Generation Resource would be unavailable; or

(c) ERCOT has not completed its reliability analysis and will need additional time to complete the assessment.

(3) Within 60 days after receiving the NSO ERCOT shall complete its reliability analysis described in paragraph (3) of Section 3.14.1.2 and, if it has not already done so, ERCOT shall issue a Market Notice stating whether the Generation Resource is required to support ERCOT System reliability during the portion of the year when the Generation Resource would be unavailable.

3.14.1.3 ERCOT Board Approval of RMR and MRA Agreements

(1) If ERCOT determines that an RMR or MRA Agreement is a cost-effective solution to remedy a performance deficiency for which the suspending Generation Resource has a material impact as described in paragraph (3) of Section 3.14.1.2, ERCOT Evaluation Process, or if ERCOT has identified such a performance deficiency but has determined that entering into an RMR or MRA Agreement is not a cost-effective solution to that performance deficiency, then ERCOT shall present this finding to the ERCOT Board for approval. In seeking such approval, ERCOT shall stipulate to the ERCOT Board that:

(a) The Resource Entity provided a complete and timely NSO including a sworn attestation supporting its claim of pending Generation Resource closure;

(b) ERCOT received all of the data necessary to evaluate the need for and provisions of the RMR or MRA Agreement, and that information was posted on the MIS Secure Area by ERCOT as it became available to ERCOT;

(c) When executed, the signed RMR or MRA Agreement will comply with the ERCOT Protocols and be posted on the MIS Secure Area;

(d) ERCOT evaluated:

(i) The reasonable alternatives to a specific RMR Agreement as set forth in Section 3.14.1, Reliability Must Run, and compared the alternatives against the feasibility, cost and reliability impacts of the signed RMR Agreement;

(ii) The timeframe in which ERCOT expects each unit to be needed for reliability; and

(iii) The specific type and scope of reliability concerns identified for each RMR Unit or MRA as applicable.

(2) ERCOT shall execute the RMR or MRA Agreement as soon as feasible after receiving ERCOT Board approval to do so.

(3) ERCOT shall post on the MIS Secure Area, as they become available, unit-specific studies, reports, and data, by which ERCOT justified entering into the RMR or MRA Agreement.

3.14.1.4 Exit Strategy from an RMR Agreement

(1) No later than 90 days after the execution of an RMR Agreement, ERCOT shall report to the Board and post on the MIS Secure Area a list of feasible alternatives that may, at a future time, be more cost-effective than the continued renewal of the existing RMR Agreement. Through the ERCOT System planning process, ERCOT shall develop a list of potential alternatives to the service provided by the RMR Unit. At a minimum, the list of potential alternatives that ERCOT must consider include, building new or expanding existing Transmission Facilities, installing voltage control devices, soliciting or buying by auction interruptible Load from Retail Electric Providers (REPs), or extending the existing RMR Agreement on an annual basis. If a cost-effective alternative to the service provided by the RMR Unit is identified, ERCOT shall provide a proposed timeline to study and/or implement the alternative.

3.14.1.5 Evaluation of Alternatives

(1) In evaluating responses to the RFP for MRAs, ERCOT shall not consider any response that, in ERCOT's sole opinion, does not facially demonstrate that the proposed MRA meets the eligibility requirements specified in Section 3.14.4.1, Overview and Description of MRAs, and the availability criteria and other conditions specified in the RFP for MRAs.

(2) ERCOT shall consider any of the following options to resolve an identified performance deficiency:

(a) The Generation Resource proposed for suspension of operations;

(b) All acceptable MRA proposals; and

(c) Any transmission upgrades that can be implemented prior to the time period for which the performance deficiency has been identified.

(3) ERCOT staff shall select the option or combination of options, if any, that most cost-effectively address the performance deficiency, as long as the cost of the selected options is justified given the possible impact to Customers due to the performance deficiency. If ERCOT determines that no option cost-effectively resolves the performance deficiency, then ERCOT shall not select any option. In selecting the most cost-effective option, ERCOT will consider the following factors:

(a) The degree to which the option addresses the identified performance deficiency;

(b) The total expected cost of each option;

(c) Expected unit performance of the Generation Resource proposed for suspension of operations, including start-up time, minimum run-time, minimum down-time, and historical unit outage data;

(d) Operational limitations of proposed MRAs, including start-up times, minimum run-times, ramp periods, and return-to-service times;

(e) Other operational constraints or operational benefits of the proposed option; and

(f) Any other factors which ERCOT determines are relevant to the evaluation, and for which ERCOT can develop quantifiable criteria with which to evaluate all proposed options.

(4) In evaluating the expected impact to Customers due to the performance deficiency, ERCOT shall consider the following factors:

(a) Expected amount of Customer Demand affected (MWh);

(b) Expected number of hours during which Customers will be affected;

(c) Number of Customers affected;

(d) Possible additional Customer impacts due to unforeseen conditions, such as Generation Resource unavailability, transmission circuit Outages, or Load variation due to extreme weather; and

(e) Potential economic impact to Customers.

(5) ERCOT staff shall recommend the selected option or options to the ERCOT Board of Directors for approval, or shall recommend that the ERCOT Board of Directors decline to accept any option, if no eligible, cost-effective option has been identified. ERCOT staff shall provide sufficient information to justify its recommendation. The ERCOT Board of Directors may approve or reject the proposed recommendation, or may direct ERCOT

staff to pursue an agreement to procure one or more options not proposed by ERCOT staff.

3.14.1.6 Transmission System Upgrades Associated with an RMR and/or MRA Exit Strategy

(1) This Section applies only to RMR exit strategies corresponding to specific RMR or MRA Agreements that have not been terminated.

(a) ERCOT and the TSP(s) responsible for constructing any upgrades to the Transmission Facilities that are part of an RMR or MRA exit strategy shall coordinate construction clearances necessary to allow timely completion of all planned Transmission Facilities upgrades.

(b) The TSP(s) responsible for constructing upgrades to the Transmission Facilities that are part of an RMR or MRA exit strategy shall establish and send to ERCOT estimated Outage information, including completion dates and associated model information to ERCOT per Section 3.1.4, Communications Regarding Resource and Transmission Facilities Outages. For purposes of this Section, a Transmission Facility upgrade will be considered initiated upon the TSP authorizing any expenditures on the upgrade including, but not limited to, material procurement, right-of-way acquisition, and regulatory approvals.

(c) Upon initiation of the project, the TSP(s) responsible for constructing upgrades relating to the Transmission Facilities that are part of an RMR or MRA exit strategy shall provide to ERCOT monthly updates of the project's status, noting any acceleration or delay in planned completion date. ERCOT shall report this data through the MIS as described in Section 12.2, ERCOT Responsibilities. Within 60 days of the completion date shown in the Notice provided per Section 3.1.4, for the Transmission Facilities upgrades, the TSP shall coordinate more timely updates if the timeline changes significantly.

(d) Within ten Business Days after completion of the Transmission Facilities upgrades that are part of an RMR or MRA exit strategy, ERCOT shall publish a Market Notice of such completion and the effective date of termination of the associated RMR or MRA Agreement.

3.14.1.7 RMR or MRA Contract Termination

(1) This Section applies only to RMR exit strategies corresponding to specific RMR or MRA Agreements that have not been terminated.

(2) Once a suitable RMR or MRA exit strategy has been developed as defined in Section 3.14.1.4, Exit Strategy from an RMR Agreement, and the strategy has been approved by the ERCOT Board and the affected TSP(s), the TSP(s) responsible for the Transmission Facilities upgrades, when requested by ERCOT, shall submit to ERCOT:

(a) A preliminary construction outage schedule necessary to complete the Transmission Facilities upgrades. Submissions, changes, approvals, rejections, and withdrawals regarding the preliminary construction outage schedule shall be processed through the ERCOT Outage Scheduler on the ERCOT MIS. Such construction outage schedule shall be updated monthly; or

(b) A Certificate of Convenience and Necessity (CCN) application timeline for projects requiring such PUCT certification. Once a CCN has been granted by the PUCT, the TSP(s) shall be required to meet the requirements in item (a) above.

(3) ERCOT shall review and approve or reject each construction outage schedule as provided in accordance with procedures developed by ERCOT in compliance with Section 3.1, Outage Coordination.

(4) The TSP(s) responsible for the Transmission Facilities upgrades that are part of an RMR or MRA exit strategy shall provide to ERCOT a project status and an estimated project completion date within five Business Days of ERCOT's request.

(5) If ERCOT determines that a mutually agreeable preliminary construction outage schedule can be accommodated during the fall, winter, or spring, ERCOT and the TSP shall collaborate to determine if the 90 day termination notice for the RMR and/or MRA can be issued as soon after the summer load Season of the preceding year as possible and publish a Market Notice of these terminations. ERCOT and the TSP may give consideration to the risk of the decision to terminate the RMR and/or MRA Agreement and any options, such as RAPs and/or Mitigation Plans that could be used to mitigate transmission construction delays.

3.14.1.8 RMR and/or MRA Contract Extension

(1) This Section applies only to RMR exit strategies corresponding to specific RMR or MRA Agreements that have not been terminated.

(a) Forty-five days prior to the termination date of an existing RMR or MRA Agreement, pursuant to the 90-day termination notice as described in paragraph A(2) of Section 3, Term and Termination, of Section 22, Attachment B, Standard Form Reliability Must-Run Agreement, ERCOT shall assess the likelihood of completion of the Transmission Facilities upgrade project(s) or other exit strategies necessary to allow termination of an existing RMR or MRA Agreement based on the updates of project status provided by the TSP(s). If ERCOT determines that a delay in the termination date of the existing RMR or MRA Agreement is necessary to allow completion of the Transmission Facilities upgrade(s), it shall provide written Notice to the Resource Entity that owns or controls the RMR Unit or the QSE that represents the MRA of its intent to execute an extension to the existing RMR or MRA Agreement no later than 30 days prior to the planned termination date. Within 24 hours of ERCOT providing this Notice to the Resource Entity that owns or controls the RMR Unit or the QSE that represents the MRA, ERCOT shall issue a Market Notice on its intent to execute an extension to the existing RMR or MRA Agreement. The Market Notice must contain the name and seasonal MW ratings of the RMR Unit or MRA and the expected duration of the contract extension, including the expected termination date. ERCOT shall notify the ERCOT Board of the extension at the ERCOT Board's next regularly scheduled meeting.

(b) Forty-five days prior to the expiration date of an existing RMR or MRA Agreement for which the Resource Entity that owns or controls the RMR Unit or the QSE that represents the MRA has applied for renewal, ERCOT shall assess the likelihood of completion of the Transmission Facilities upgrade project(s) necessary to eliminate the reliability need for a Resource with an existing RMR or MRA Agreement based on the updates of project status provided by the TSP(s). If ERCOT determines that an extension of the existing RMR or MRA Agreement of no more than 90 days would allow completion of the Transmission Facilities upgrade(s), it shall provide written Notice to the Resource Entity that owns or controls the RMR Unit or the QSE that represents the MRA of its intent to execute an extension to the existing RMR or MRA Agreement no later than 30 days prior to the planned expiration date. Within 24 hours of ERCOT providing this Notice to the Resource Entity that owns or controls the RMR Unit or the QSE that represents the MRA, ERCOT shall issue a Market Notice on its intent to execute an extension to the existing RMR or MRA Agreement. The Market Notice must contain the name and seasonal MW ratings of the RMR Unit or MRA and the expected duration of the contract extension, including the expected termination date. ERCOT shall notify the ERCOT Board of the extension at the ERCOT Board's next regularly scheduled meeting.

(c) ERCOT may extend the existing RMR or MRA Agreement as necessary to allow completion of the Transmission Facilities upgrade(s), but in no event shall the extension last more than 90 days from the termination or expiration date of the existing RMR or MRA Agreement.

(d) Forty-five days prior to the end of the period for which the existing RMR or MRA Agreement has been extended, ERCOT shall assess whether the transmission upgrades are likely to be completed. If ERCOT determines that the upgrades are not likely to be completed, ERCOT shall enter into negotiations with the Resource Entity that owns or controls the RMR Unit or the QSE that represents the MRA to negotiate a new RMR or MRA Agreement to allow completion of the planned transmission upgrades. ERCOT shall issue a Market Notice on or before the date that extension negotiations begin with the Resource Entity that owns or controls the RMR Unit or the QSE that represents the MRA. The Market Notice must contain the name and seasonal MW ratings of the RMR Unit or MRA and the expected duration of the contract extension, including the expected termination date. Additionally, the Market Notice must contain a description of the exit strategy and the status of progress of exit strategy projects. ERCOT shall notify the ERCOT Board of the extension at the ERCOT Board's next regularly scheduled meeting.

3.14.1.9 Generation Resource Status Updates

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

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

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

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

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

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

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

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

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

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

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

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

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

(14) Before retiring and decommissioning either a Mothballed Generation Resource this is mothballed indefinitely or an RMR Unit that would otherwise become a Mothballed Generation Resource upon expiration of an RMR Agreement, a Resource Entity shall

notify ERCOT of the expected retirement by submitting a completed Notification of Change of Generation Resource Designation form (Section 22, Attachment H). The date of retirement indicated on the form shall comply with the requirements of Section 3.10.1, Time Line for Network Operations Model Changes.

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

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

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

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

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

3.14.1.10 Eligible Costs

(1) "Eligible Costs" are costs that would be incurred by the RMR Unit owner to provide the RMR Service, excluding fuel costs or other costs the RMR Unit would have incurred anyway had it been mothballed or shut down.

(a) Examples of Eligible Costs include the following to the extent they each meet the standard for eligibility:

(i) Direct labor to operate the RMR Unit during the term of the RMR Agreement;

(ii) Materials and supplies directly consumed or used in operation of the RMR Unit during the term of the RMR Agreement;

(iii) Services necessary to operate the RMR Unit during the term of the RMR Agreement;

(iv) Costs associated with emissions credits used as a direct result of operation of the RMR Unit under direction from ERCOT, or emissions reduction equipment as may be required according to terms of the RMR Agreement;

(v) Costs associated with maintenance:

(A) Due to required equipment maintenance;

(B) Due to replacement to alleviate unsafe operating conditions;

(C) Due to regulatory requirements, with compliance dates during the term of the RMR Agreement (any such compliance dates and requirements shall be explicitly defined in the RMR Agreement); or

(D) To ensure the ability to operate the RMR Unit consistent with Good Utility Practice;

(vi) Reservation and transportation costs associated with firm fuel supplies not recovered under Section 6.6.6.2, RMR Payment for Energy;

(vii) Property taxes and other taxes attributable to continuing to operate the RMR Unit during the term of the RMR Agreement;

(viii) General fund transfers or similar direct expenses incurred by a Municipally Owned Utility (MOU) if it is required to pay a portion of its revenues to the municipality. If the RMR payment to the MOU is subject to such a requirement, this expense is an incremental cost directly associated with the RMR Unit;

(ix) Costs based on a long-term service agreement (LTSA), provided that:

(A) The maintenance costs to be included are incremental and consistent with the definitions of the costs within the scope of the RMR Agreement and these Protocols;

(B) The cost of each component is specifically set by the LTSA;

(C) ERCOT must be able to verify the incremental or variable maintenance costs ($/MWh) or ($/start) described in the LTSA; and

(D) The LTSA is in effect during the term of the RMR Agreement and available to ERCOT for review; and

(x) Non-fuel costs to return a mothballed RMR Unit, or an RMR Unit that had ceased operations permanently due to a Forced Outage, to service provided that:

(A) The costs were incurred between the effective date of the RMR Agreement and the termination date of the RMR Agreement; and

(B) The costs do not include costs the RMR Unit owner would have incurred had the RMR Unit remained mothballed or under Forced Outage.

(b) Examples of costs not included as Eligible Costs are:

(i) Depreciation expense, return on equity, and debt and interest costs;

(ii) Property taxes and other taxes not attributable to continuing to operate the RMR Unit;

(iii) Income taxes of the RMR Unit owner or operator;

(iv) Labor and material costs associated with other, non-RMR Generation Resources at the same facility;

(v) Cost of parts inventory not used by the RMR Unit during the term of the Agreement;

(vi) Costs attributed to other Resources in the power generation station; and

(vii) Any other costs the Resource Entity that owns the RMR Unit would have incurred even if the RMR Unit had been mothballed or shutdown.

3.14.1.11 Budgeting Eligible Costs

(1) The owner of an RMR Unit shall provide a good faith preliminary budget, including detailed monthly estimates of its Eligible Costs to ERCOT, to support its calculation of the initial Standby Cost in Part III of the Notification of Suspension of Operations submitted to ERCOT pursuant to paragraph (4) of Section 3.14.1.2, ERCOT Evaluation Process, in a format acceptable to ERCOT. ERCOT shall review the budget and may reject any item it determines to be unreasonable. The owner of the RMR Unit and ERCOT may mutually agree to modify the expected contract capacity and Target Availability of the RMR Unit as necessary to account for any budget item that is rejected.

(2) As part of the MRA evaluation process, the QSE that represents the MRA must notify ERCOT if any contributed capital expenditures are required under the proposed MRA Agreement. The QSE that represents the MRA shall provide an explanation and a good faith preliminary budget for the contributed capital expenditures in a format acceptable to ERCOT. ERCOT shall review and may approve the budget to determine which costs would be considered contributed capital expenditures in accordance with Section 3.14.1.19, Charge for Contributed Capital Expenditures.

(3) ERCOT may retain a third party mutually agreeable to ERCOT and the owner of the RMR Unit to assist in the evaluation of a submitted budget, whether for initial or updated costs. The cost of such a third party will be allocated pursuant to paragraph (2) of Section 6.6.6.6, Method for Reconciling RMR Actual Eligible Costs, RMR and MRA Contributed Capital Expenditures, and Miscellaneous RMR Incurred Expenses.

(4) The Eligible Cost budgeting process is as follows:

(a) The RMR Unit owner shall supply ERCOT a preliminary Eligible Cost budget for the expected RMR Agreement period starting with the anticipated effective date of the RMR Agreement.

(b) The preliminary Eligible Cost budget should be submitted in conjunction with Part III of the NSO, as specified in paragraph (2) of Section 3.14.1.1, Notification of Suspension of Operations, and paragraph (6) of Section 3.14.1.2.

(c) The budget will include Eligible Costs categorized in terms of:

(i) Base Cost of Operations, by month, which includes Eligible Costs that are independent of the levels of operation, Outages and non-Outage maintenance;

(ii) Outage Maintenance Cost, which includes Eligible Costs attributable to Planned or Maintenance Outages and/or inspections occurring during the term of the RMR Agreement, by month. Maintenance alternatives available during any Planned or Maintenance Outage must be presented to ERCOT for determination of the alternative to be performed and paid for under the RMR Agreement. The RMR Unit owner must present ERCOT with a budget for each option, benefits of each alternative, unit availability impact associated with not performing each alternative, and a recommendation to facilitate ERCOT's selection process. If no reasonable alternatives are available then the RMR Unit owner shall provide an affirmation to that effect;

(iii) Non-Outage Maintenance Cost, by month, which includes non-recurring Eligible Costs that are independent of a particular scheduled Outage. Non-Outage maintenance alternatives available during any scheduled Outage must be presented to ERCOT for determination of the alternative to be performed and paid for under the RMR Agreement. The RMR Unit owner must present ERCOT with a budget for each option, benefits of each alternative, unit availability impact associated with not performing each alternative, and a recommendation to facilitate ERCOT's selection process. If no reasonable alternatives are available then an affirmation by the RMR Unit owner to that effect must be included in the RMR Agreement;

(iv) For Resources without approved verifiable costs, the following data is required:

(A) Variable Operations & Maintenance (O&M) costs ($/start), from start to Low Sustained Limit (LSL), for each start type:

(1) Cold;

(2) Hot; and

(3) Intermediate;

(B) Operating variable O&M costs ($/MWh):

(1) At LSL; and

(2) Above LSL;

(C) Average generation from breaker close to LSL (MWh), for each start type:

(1) Cold;

(2) Hot; and

(3) Intermediate;

(D) Fuel consumption (MMBtu/start), for each start type:

(1) Cold;

(2) Hot; and

(3) Intermediate;

(E) Startup Fuel Percentage from start to LSL, for each start type:

Fuel Type	Hot (%)	Intermediate (%)	Cold (%)
Gas			
Fuel Oil			
Solid Fuel			

(F) Operating Fuel Percentage:

Fuel Type	At LSL	Above LSL
Gas		
Fuel Oil		
Solid Fuel		

(G) Input/output curve coefficients;

(v) Other budget items means Eligible Costs not clearly identifiable in the previous three categories including:

(A) Environmental emission credit consumption (or purchase as explicitly defined under the RMR Agreement, to operate the unit) includes the opportunity cost for using emission credits through the combustion of fuel feedstock by the RMR Unit. Costs must be based on verifiable market data as supplied by the RMR Unit owner; and

(B) "Compliance Costs," which includes foreseeable costs to comply with regulations, Federal or state that have a compliance deadline that occurs during the term of the RMR Agreement.

(d) Thirty days after receipt of the preliminary Eligible Costs budget, ERCOT shall notify the RMR Unit owner of its selections under the alternatives provided in the preliminary budget. The RMR Unit owner and ERCOT shall set the Target Availability monthly values consistent with the options presented to and selected by during the budgeting process. The Target Availability shall be mutually agreed by ERCOT and the RMR Unit owner by taking into account a negotiated amount of predicted Forced Outages, Planned Outages identified during the budgeting process, and any budget items rejected by ERCOT.

(e) If applicable, the RMR Unit owner should provide a written description of the type of work needed for the Resource to achieve the operational conditions for the RMR Service, in accordance with the capacity and Target Availability requirements. This should include:

(i) A description of the equipment needed;

(ii) An indication if the equipment is anticipated to be expensed or capitalized;

(iii) The estimated life and depreciation schedule of each capitalized component;

(iv) The estimated salvage value of the capitalized components;

(v) The estimated time to install each piece of equipment; and

(vi) The expected time of completion of work needed to restore the Resource to operational status.

3.14.1.12 Calculation of the Initial Standby Cost

(1) The initial Standby Cost shall be calculated by dividing the total monthly approved budget cost over the term of the RMR Agreement by the total hours for the term of the RMR Agreement.

3.14.1.13 Updated Budgets During the Term of an RMR Agreement

(1) Upon commencement of the RMR Agreement, based on the Agreement term, the RMR Unit owner shall identify planned equipment installations as anticipated to be expensed or capitalized and shall update the estimated salvage value of capitalized components. The RMR Unit owner shall submit to ERCOT updated budget information every three months, in a format consistent with the preliminary budget, for the remainder of the term of the RMR Agreement. ERCOT shall review updated budget information for reasonableness and may reject any item it determines to be unreasonable. The owner of the RMR Unit and ERCOT may mutually agree to modify the contract capacity and Target Availability of the RMR Unit to account for any such budget item rejection.

(2) ERCOT will use approved updated budget information to update the total RMR costs expected to be incurred over the remaining term of the RMR Agreement. If the total costs over the remaining term of the RMR Agreement change by more than 10% with respect to those costs anticipated for the same period in the most recently approved budget, the RMR Standby Cost will be recalculated. The revised Standby Cost will be

recalculated by dividing the remaining budgeted costs over the number of remaining hours for which the RMR Unit is under an RMR Agreement.

(3) ERCOT shall issue a Market Notice describing the revised Standby Cost at least ten calendar days prior to the effective date of a change to the Standby Cost. The effective date of a revised Standby Cost will always be on the first day of a calendar month.

3.14.1.14 Reporting Actual RMR Eligible Costs

(1) The RMR Unit owner shall provide ERCOT with documentation supporting actual Eligible Costs on a monthly basis in a form and a level of detail acceptable to ERCOT for ERCOT to verify that all Eligible Costs are actual and appropriate. Submitted actual Eligible Costs must be categorized consistently with budgeted Eligible Costs. Actual cost data must be submitted on time by the Resource Entity for the RMR Unit and then verified by ERCOT so the actual cost data can be reflected in the Final or True-Up Settlement Statement.

(2) To be considered timely for the final, actual cost data for month ‘x’ must be submitted by the 16^{th} of the month following month ‘x’. To be considered timely for the true-up, actual cost data for month ‘x’ must be submitted 60 days prior to the publishing date of the True-Up Settlement Statement for the first day in month ‘x’. Any deviation in filing actual cost data in accordance with this calendar must be requested of ERCOT, by the QSE representing an RMR Unit. Such request for deviation shall contain the reason for the inability to meet the calendar and an expected date that the cost data will be provided to ERCOT. At its discretion ERCOT may choose to honor such a request. No later than two Business Days following its decision, ERCOT shall issue a Market Notice of any such request and its response thereto. In the event, that actual cost data is not submitted in accordance with the calendar or approved deviation for the true-up, then the cost for the portion of eligible cost that has not been submitted is deemed to be zero.

3.14.1.15 Reporting Actual MRA Eligible Costs

(1) The QSE that represents the MRA that has received contributed capital expenditures shall provide ERCOT with evidence of the actual costs associated with the capital expenditures on a monthly basis in a level of detail sufficient for ERCOT to verify that all capital contributions costs are actual and appropriate.

3.14.1.16 Reconciliation of Actual Eligible Costs

(1) ERCOT shall issue a miscellaneous Invoice to charge the QSE representing the RMR Unit for any identified over-payments for actual Eligible Costs. Funds collected will be distributed in accordance with Section 6.6.6.6, Method for Reconciling RMR Actual Eligible Costs, RMR and MRA Contributed Capital Expenditures, and Miscellaneous RMR Incurred Expenses.

3.14.1.17 Incentive Factor

(1) Subject to the reductions described in paragraphs (2) and (3) below, the Incentive Factor for RMR Agreements is equal to 10% of the actual Eligible Costs, excluding fuel costs and reservation and transportation costs associated with firm fuel supplies as described in paragraph (1)(a)(vi) of Section 3.14.1.10, Eligible Costs. The Incentive Factor for RMR Agreements is not applied to capital expenditures as described in Section 3.14.1, Reliability Must Run, or to capital expenditures reclassified as an expense in accordance with paragraph (3)(d) of Section 3.14.1.19, Charge for Contributed Capital Expenditures. The Incentive Factor shall never be less than zero.

(2) The Incentive Factor shall be reduced if the RMR Unit fails to perform to the contracted capacity during a Capacity Test as described in the RMR Agreement. The reduction will be linear, with a 2% reduction in the Incentive Factor for every 1% of reduced Capacity.

(3) The Incentive Factor shall be reduced if the "Hourly Rolling Equivalent Availability Factor" of the RMR Unit is less than the Target Availability (i.e. the "Actual Availability", as defined below, is less than the Target Availability).

(a) The reduction will be linear; with a 2% reduction in the Incentive Factor payment for every 1% of the Hourly Rolling Equivalent Availability Factor less than the Target Availability stated in the RMR Agreement. The RMR Unit's Actual Availability shall be calculated on an hourly rolling six-month average basis.

(b) The calculation is made by dividing the total MW of available capacity per hour according to its final COP by the total MW of contracted capacity per hour for the previous 4380 hours.

(c) For purposes of this calculation, any hour within the previous 4380-hour period that precedes the start date of the RMR Agreement is treated as if 100% of the capacity of the unit was available for the hour.

3.14.1.18 Major Equipment Modifications

(1) During the term of an RMR Agreement, in the event that major equipment modifications are required in order for the RMR Unit to provide RMR Service (such as installation of environmental control equipment), ERCOT and the RMR Unit owner shall negotiate in good faith concerning changes to the terms of the RMR Agreement.

3.14.1.19 Charge for Contributed Capital Expenditures

(1) This Section applies to any RMR or MRA Agreement entered into by ERCOT and a Resource Entity or QSE on or after October 12, 2016.

(2) For purposes of this Section, contributed capital expenditures are defined as expenditures that were made to ensure the availability of an RMR Unit or MRA in connection with an

RMR or MRA Agreement, that were settled in accordance with the Settlement processes in the ERCOT Protocols, and that would ordinarily be capitalized under Generally Accepted Accounting Principles (GAAP) or International Accounting Standards (IAS) assuming ongoing operation of the RMR Unit or MRA. Consistent with the process described in Section 3.14.1.11, Budgeting Eligible Costs, ERCOT will identify contributed capital expenditure items included in each category of submitted Eligible Costs as defined in Section 3.14.1.10, Eligible Costs, or submitted with any MRA budgets.

(3) A QSE that has received payments from ERCOT for contributed capital expenditures pursuant to an RMR or MRA Agreement entered into on or after October 12, 2016 must refund to ERCOT the contributed capital expenditures as follows:

(a) At the end of the RMR Agreement, if the Resource Entity chooses not to have the Generation Resource participate in energy or Ancillary Service markets, the QSE representing the Resource Entity shall repay, in a lump sum payment, the positive salvage value associated with the contributed capital expenditures, as estimated at the time of the RMR Agreement.

(b) At the end of the MRA Agreement, if the QSE that represents the MRA chooses not to have the MRA participate in energy or Ancillary Service markets, the QSE representing the MRA shall repay, in a lump sum payment, the positive salvage value associated with the contributed capital expenditures, as estimated at the time of the MRA Agreement. In addition, the QSE that represents the MRA must repay, in a lump sum payment, the value of contributed capital expenditures in excess of the actual cost of the capitalized equipment.

(c) If an RMR Unit or MRA participates in the energy or Ancillary Service markets at any time after the termination date of the RMR or MRA Agreement, the Resource Entity that owns or controls the RMR Unit or the QSE that represents the MRA shall repay, in a lump sum payment, 100% of the remaining book value of the capitalized equipment and capitalized installation charges based on straight-line depreciation over the estimated life of the capitalized component(s) as of the termination date of the RMR or MRA Agreement in accordance with GAAP or IAS standards for electric utility equipment, plus 10% of the value of any accelerated tax depreciation associated with the capital contribution taken by the Resource Entity that owns or controls the RMR Unit or the QSE that represents the MRA during the term of the RMR or MRA Agreement, less any remaining positive salvage value associated with the contributed capital expenditures that was previously repaid in accordance with paragraph (a) or (b) above. The estimated life shall be based on documentation provided by the manufacturer; or, if installing used equipment, the estimated life may be based on an approximation agreed to by the Resource Entity that owns or controls the RMR Unit or the QSE that represents the MRA and ERCOT, but in no event shall the estimated life be less than the equipment life used for federal income tax purposes. The value of the accelerated tax depreciation for each year shall be the difference between the straight line figure and the appropriate Modified Accelerated Cost Recovery

System (MACRS) depreciation schedule for the equipment, multiplied by the statutory tax rate. The calculation of the accelerated depreciation as described herein must be supported by an attestation executed by an officer or executive with the authority to bind the Resource Entity or the QSE representing the Resource Entity.

(d) If additional contributed capital expenditures are identified subsequent to execution and during the term of the RMR or MRA Agreement, the applicable repayment amounts as determined in paragraphs (a), (b), or (c) above will be modified accordingly.

(e) The amount of contributed capital expenditures may be adjusted by ERCOT when early termination in accordance with the RMR Agreement results in a reclassification of capital expenditures to expenses in accordance with GAAP or IAS.

(f) If the Resource Entity that owns or controls the RMR Unit or the QSE that represents the MRA is required to pay a lump sum payment of contributed capital expenditures per paragraph (a), (b), or (c) above, then ERCOT will issue a Market Notice identifying the amount of the lump sum payment within five Business Days of termination of the RMR or MRA Agreement.

(i) ERCOT shall issue a miscellaneous Invoice charging the QSE for the applicable amounts under paragraphs (a), (b), or (c) above. ERCOT will issue a Market Notice after completion of the collection and disbursement of the repaid contributed capital expenditures.

(ii) ERCOT shall distribute the repayment to QSEs representing Load per Section 6.6.6.6, Method for Reconciling RMR Actual Eligible Costs, RMR and MRA Contributed Capital Expenditures, and Miscellaneous RMR Incurred Expenses.

3.14.1.20 Budgeting Fuel Costs

(1) The RMR Unit owner shall supply ERCOT a preliminary monthly fuel cost budget for the anticipated term and effective date of the RMR Agreement. The fuel cost budget must include information pertaining to the cost of the fuel feedstock, including where appropriate transportation costs and terms, as well as fuel storage costs and terms, and any other fuel contract provisions (e.g. “take or pay” provisions) that may impact the cost of all fuels anticipated to be used by the RMR Unit over the life of the RMR Agreement and must include fuel costs categorized in terms of:

(a) Primary fuel; and

(b) Secondary fuel.

(2) The estimated fuel payments may include a fuel adder to better approximate expected fuel costs, which may be adjusted from time to time by mutual agreement of the RMR Unit owner and ERCOT. The fuel adder shall represent the difference between the forecasted average fuel price and the forecasted average of the relevant index price over the RMR contract period. The fuel adder must also include the forecasted cost of transporting and delivering fuel and fuel imbalance fees to the Resource. The RMR Unit owner must provide to ERCOT supporting documentation indicating how the fuel adder was determined.

(3) The RMR Unit owner shall provide good faith estimates of the RMR Unit input/output curve coefficients to ERCOT with its Notification of Suspension of Operations.

(4) Based on production figures provided to the RMR Unit owner by ERCOT, the RMR Unit owner shall also provide ERCOT fuel supply options available for the RMR Unit. For each option, the RMR Unit owner shall detail the associated impacts on the fuel and non-fuel budgets and on the availability of the RMR Unit. If no reasonable alternatives are available then an affirmation by the RMR Unit owner to that effect must be included in the RMR Agreement. If there are available fuel options, then no less than 30 days after the receipt of the fuel supply options, ERCOT shall notify the RMR Unit owner of its fuel supply option selection.

3.14.1.21 Reporting Actual Eligible Fuel Costs

(1) The RMR Unit owner shall provide ERCOT with actual fuel costs on a monthly basis for the RMR Unit in a level of detail sufficient for ERCOT to verify that all fuel costs are actual and appropriate. ERCOT shall perform a true-up of the estimated fuel costs using the submitted and verified actual fuel costs for the RMR Unit. Actual cost data must be submitted on time by the Resource Entity for the RMR Unit and then verified by ERCOT so the actual cost data can be reflected in the True-Up Settlement Statement. To be considered timely for the final, actual cost data for month ‘x’ must be submitted by the 16th of the month following month ‘x.’ To be considered timely for the true-up, actual cost data for month ‘x’ must be submitted 60 days prior to the publishing date of the True-Up Settlement Statement for the first day in month ‘x.’ Any deviation in filing actual cost data in accordance with this calendar must be requested of ERCOT, by the QSE representing an RMR Unit. Such request for deviation shall contain the reason for the inability to meet the calendar and an expected date that the cost data will be provided to ERCOT. At its discretion ERCOT may choose to honor such a request. No later than two Business Days following its decision, ERCOT shall issue a Market Notice of any such request and its response thereto. In the event that actual cost data is not submitted in accordance with the timeline or is not an approved deviation for the true-up, then the cost for the portion of Eligible Cost that has not been submitted is deemed to be zero.

(2) Actual fuel costs must be appropriate actual costs attributable to ERCOT’s scheduling and/or deployment of the RMR Unit. Actual fuel costs may include cost of fuel (including the cost of exceeding swing gas contract limits, additional gas demand costs set by fuel supply, or transportation contracts); demand fees, imbalance penalties,

transportation charges, and cash out premiums. In addition, actual fuel costs may include costs incurred to:

(a) Keep the boiler(s) warmed, if approved in advance by ERCOT; and

(b) Test the RMR Unit prior to or during the term of the RMR Agreement, if approved in advance by ERCOT.

3.14.2 Black Start

(1) Each Generation Resource providing BSS must meet the requirements specified in North American Electric Reliability Corporation (NERC) Reliability Standards and the Operating Guides.

(2) Each Generation Resource providing BSS must meet the technical requirements specified in Section 8.1.1, QSE Ancillary Service Performance Standards, and Section 8.1.1.1, Ancillary Service Qualification and Testing.

(3) Bids for BSS are due on or before February 15^{th} of each three-year period. Bids must be evaluated based on evaluation criteria attached as an appendix to the request for bids and contracted by December 31^{st} for the following three-year period. ERCOT shall ensure BSSs are arranged, provided, and deployed as necessary to reenergize the ERCOT System following a Blackout or Partial Blackout.

(a) Resources shall disclose any weather-related limitations that could affect the Resource's ability to provide BSS using the form provided in Section 22, Attachment M, Generation Resource Disclosure Regarding Bids for Black Start Service, as part of a bid to provide BSS.

(b) BSS bids shall include the hourly stand-by price and the BSS Back-up Fuel costs where applicable.

(c) When a Resource is selected to provide BSS, the Black Start Resource shall be required to complete all applicable testing requirements as specified in Section 8.1.1.2.1.5, System Black Start Capability Qualification and Testing.

(d) ERCOT shall provide a list of all prospective Black Start Resources that responded to the RFP for BSS to the impacted TSPs no later than seven days after the date on which bids for BSS are due. Any feedback from affected TSPs shall be limited to the identification of transmission constraints that may adversely impact the ability of the Black Start Resource to energize the Next Start Resource and shall be due to ERCOT by March 1st of that year. ERCOT shall share the feedback with the QSE representing the prospective Black Start Resource as soon as practicable. The QSE representing the Black Start Resource shall have the option to provide a response to any feedback provided by an affected TSP.

(4) ERCOT may schedule unannounced Black Start testing, to verify that BSS is operable as specified in Section 8.1.1.2.1.5.

(5) QSEs representing Generation Resources contracting for BSSs shall participate in training and restoration drills coordinated by ERCOT.

(6) ERCOT shall periodically determine and review the location and number of Black Start Resources required, as well as any special transmission or voice communication needs required. ERCOT and providers of this service shall meet the requirements as specified in the Operating Guides and in NERC Reliability Standards.

(7) A Resource Entity representing a Black Start Resource may request that an alternate Generation Resource which is connected to the same black start primary and secondary cranking path as the original Black Start Resource be substituted in place of the original Black Start Resource during the three year term of an executed Standard Form Black Start Agreement (Section 22, Attachment D, Standard Form Black Start Agreement) if the alternate Generation Resource meets testing and verification under established qualification criteria to ensure BSS.

(a) ERCOT, in its sole discretion, may reject a Resource Entity's request for an alternate Generation Resource and will provide the Resource Entity an explanation of such rejection.

(b) If ERCOT accepts the alternative Generation Resource as the substituted Black Start Resource, such acceptance shall not affect the original terms, conditions and obligations of the Resource Entity under the Standard Form Black Start Agreement. The Resource Entity shall submit to ERCOT an Amendment to Standard Form Black Start Agreement (Section 22, Attachment I, Amendment to Standard Form Black Start Agreement) after qualification criteria has been met.

(8) For the purpose of the Black Start Hourly Standby Fee as described in Section 6.6.8.1, Black Start Hourly Standby Fee Payment, the Black Start Service Availability Reduction Factor shall be determined by using the availability for the original Black Start Resource and any substituted Black Start Resource(s), as appropriate for the rolling 4380-hour period of the evaluation.

(9) Each Generation Resource selected to provide BSS shall be prepared and able to provide BSS at any time as may be required by ERCOT, subject only to the limitations described in ERCOT Protocols or the Black Start Agreement.

(10) Each Generation Resource selected to provide BSS shall be able to utilize BSS Back-up Fuel for BSS and shall maintain a contracted amount of BSS Back-up Fuel to run the Black Start Resource for a minimum of 72 hours at its maximum output. The Generation Resource shall maintain the contracted amount of BSS Back-up Fuel at all times during the duration of the BSS contract term unless performing a BSS Back-up Fuel Switching Test or the Generation Resource is operating pursuant to a Black Start deployment event. This requirement does not apply to Resources that do not rely on purchased fuel.

(11) A Black Start Resource may utilize the contracted amount of BSS Back-up Fuel outside of BSS if ERCOT determines it is necessary during an Energy Emergency Alert (EEA) event.

(12) A Black Start Resource is not obligated to contract its full on site fuel storage capability for BSS Back-up Fuel. On site backup fuel in excess of the contracted BSS Back-up Fuel amount may be used by the Generation Resource at the discretion of the Generation Resource and ERCOT shall not prevent the Black Start Resource from utilizing the excess fuel, nor shall the Black Start Resource be required to request permission from ERCOT to utilize fuel in excess of the contracted BSS Back-up Fuel amount.

(13) ERCOT may, at its discretion, waive the BSS Back-up Fuel requirement stated in this Section, in whole or in part, if ERCOT deems necessary in order to procure a sufficient number or preferred combination of Generation Resources to provide BSS.

(14) A Resource Entity that submits a bid or is contracted to provide BSS or serve as an alternate to provide BSS with a Switchable Generation Resource (SWGR):

(a) Shall not nominate the SWGR to satisfy supply adequacy or capacity planning requirements in any Control Area other than the ERCOT Region during the term of the BSS contract;

(b) Shall submit a report to ERCOT in compliance with paragraph (2) of Section 16.5.4, Maintaining and Updating Resource Entity Information, indicating that the SWGR does not have any contractual requirement in a non-ERCOT Control Area during the term of the BSS contract; and

(c) Shall take any further action requested by ERCOT to ensure that ERCOT will be classified as the "Primary Party" for the SWGR under any agreement between ERCOT and another Control Area Operator during the term of the BSS contract.

(15) If a Resource Entity with a SWGR is contracted to provide BSS or designated as an alternate to provide BSS, the Resource Entity shall have its Black Start plan procedures approved by ERCOT. In the event of a Partial Blackout or Blackout of the ERCOT System, the Resource Entity with a SWGR shall immediately:

(a) Effectuate its Black Start plan procedures to be available to provide BSS; and

(b) Provide BSS as directed by ERCOT or the local Transmission Operator (TO).

3.14.3 Emergency Response Service

(1) ERCOT shall procure and deploy ERS with the goal of promoting reliability prior to and during energy emergencies.

3.14.3.1 Emergency Response Service Procurement

(1) ERCOT shall issue Requests for Proposals to procure ERS for each Standard Contract Term. The ERS Standard Contract Terms are as follows:

(a) December through March;

(b) April and May;

(c) June through September; and

(d) October and November.

(2) ERCOT shall procure ERS from one or more of the four following ERS service types:

(a) Weather-Sensitive ERS-10

(b) Non-Weather-Sensitive ERS-10

(c) Weather-Sensitive ERS-30

(d) Non-Weather-Sensitive ERS-30

(3) ERS offers shall be submitted only by QSEs capable of receiving both Extensible Markup Language (XML) messaging and Verbal Dispatch Instructions (VDIs) on behalf of represented ERS Resources.

(4) Each site in an ERS Generator must have an interconnection agreement with its Transmission and/or Distribution Service Provider (TDSP) prior to submitting an ERS offer and must have exported energy to the ERCOT System prior to the offer due date. An ERS Resource that cannot inject energy to the ERCOT System can only be offered as an ERS Load.

(5) In order to qualify as weather-sensitive, an ERS Load must meet one of the following criteria:

(a) The ERS Load must consist exclusively of residential sites; or

(b) The ERS Load must consist exclusively of non-residential sites and must qualify as weather-sensitive based on the accuracy of the regression baseline evaluation methodology as described in Section 8.1.3.1.1, Baselines for Emergency Response Service Loads, as an indicator of actual interval Load.

(i) ERCOT shall establish minimum accuracy standards for qualification as an ERS Load under the regression baseline evaluation methodology.

(ii) An ERS Load must have at least nine months of interval meter data to qualify as weather-sensitive under the regression baseline evaluation methodology.

(iii) ERCOT's determination that an ERS Load qualifies as a weather-sensitive ERS Load is independent of ERCOT's determination of which baseline methodologies may be appropriate for purposes of evaluating the ERS Load's performance.

(c) If a site with Distributed Renewable Generation (DRG) has been designated by the QSE to be evaluated by using its native load, the default baseline analysis shall be performed using the calculated native load.

(6) QSEs representing ERS Resources may submit offers for one or more ERS Time Periods within an ERS Standard Contract Term. ERS Time Periods shall be defined by ERCOT in the RFP for that ERS Standard Contract Term. An ERS offer is specific to an ERS Time Period. In submitting an offer, both the QSE and the ERS Resource are committing to provide ERS for that ERS Time Period if selected.

(7) A QSE may submit separate offers for an ERS Resource to provide any or all of the four ERS service types during the same or different ERS Time Periods in the same ERS Standard Contract Term, but ERCOT shall only award offers for one service type for each ERS Resource.

(8) The minimum capacity offer for an ERS Load on the weather-sensitive baseline is one half (0.5) MW; all other ERS capacity offers will have a minimum amount that may be offered of one-tenth (0.1) MW. ERS Resources may be aggregated to reach this requirement.

(9) Offers from ERS Generators must include self-serve capacity and injection capacity amounts greater than or equal to zero for each ERS Time Period offered.

(10) ERCOT may establish an upper limit, in MWs, on the amount of ERS capacity it will procure for any ERS Time Period in any ERS Standard Contract Term.

(11) A QSE's offer to provide ERS shall include:

(a) The name of the QSE representing the ERS Resource and the name of an individual authorized by the QSE to represent the QSE and its ERS Resource(s);

(b) The name of an Entity that controls the ERS Resource, and an affirmation that the QSE has obtained written authorization from the Entity to submit ERS offers on its behalf and to represent the Entity in all matters before ERCOT concerning the Entity's provision of ERS;

(c) Any information or data specified by ERCOT, including access to historical meter data, and affirmation by the QSE that it has obtained written authorization from the controlling Entity of the ERS Resource for the QSE to obtain such data;

(d) Affirmation that the controlling Entity of the ERS Resource has reviewed P.U.C. SUBST. R. 25.507, Electric Reliability Council of Texas (ERCOT) Emergency Response Service (ERS), these Protocols and Other Binding Documents relating to the provision of ERS, and has agreed to comply with and be bound by such provisions;

(e) An agreement by the QSE to produce any written authorization or agreement between the QSE and any ERS Resource it represents, as described in this Section, upon request from ERCOT or the PUCT;

(f) Affirmation that no offered capacity from any site in an ERS Resource has been or will be committed to provide any other product, service, or program during any of the hours in the ERS Time Period in the Standard Contract Term for which the offer is submitted. Such prohibited products, services, or programs include, but are not limited to, Ancillary Services, Security-Constrained Economic Dispatch (SCED), or TDSP standard offer programs. As an exception to the foregoing, a QSE may offer a site to provide ERS for an ERS Time Period in the Standard Contract Term even if the QSE has an offer pending for that same site to serve as an MRA during that ERS Time Period and Standard Contract Term; however, if the site is selected to serve as an MRA it will not be permitted to serve as ERS during any ERS Time Period in the ERS Contract Term in which it is obligated to serve as an MRA;

(g) Affirmation that the QSE and the controlling Entity the ERS Resource are familiar with any applicable federal, state or local environmental regulations that apply to the use of any generator in the provision of ERS, and that the use of such generator(s) to provide of ERS would not violate those regulations. This provision applies to both ERS Generators and to the use of backup generation by ERS Loads; and

(h) Affirmation that each offered ERS Resource satisfies at least one of the conditions set forth in paragraph (9) of Section 3.6.1, Load Resource Participation, and that all of the ERS Resource's offered Demand response capacity will be available if deployed by ERCOT during an emergency.

(12) Upon request from a QSE, ERCOT shall provide the dates and times for any deployment events or tests of any ERS site during the previous three ERS Standard Contract Terms, provided that the QSE has obtained written authorization from the ERS site to obtain the information from ERCOT. Such QSE requests shall include the following site-specific information: Electric Service Identifier (ESI ID), unique meter identifier (if applicable), or, if the site is in a Non-Opt-In Entity (NOIE) area, site name and site address.

(13) Sites associated with a Dynamically Scheduled Resource (DSR) may not participate in ERS. Offers for Resources containing sites associated with a DSR will be rejected by ERCOT. If ERCOT determines that any participating site is associated with a DSR, that site will be treated as removed from the Resource on the date the determination was made. An ERS Resource's obligation will not change as a result of any such site removal.

[NPRR1000: Delete item (13) above upon system implementation and renumber accordingly.]

(14) Each offer submitted by a QSE on behalf of an aggregated ERS Load on a weather-sensitive baseline shall include the QSE's projection of the maximum number of sites in the aggregation during the ERS Standard Contract Term. ERCOT shall review this projection and the information provided regarding the initial size of each aggregated ERS Load and shall reject any offer on behalf of such an ERS Load if the maximum size of the ERS Load projected by the QSE would violate the limits of site participation growth described in paragraph (15) below.

(15) A QSE may modify the population of an aggregated ERS Load on a weather-sensitive baseline once per month during an ERS Standard Contract Term via a process defined by ERCOT. Such adjustments shall be effective on the first day of each month following the first month. A fully validated ERS Offer form must be received by ERCOT no later than seven business days prior to the first day of the month for which is intended to be in effect.

(a) During an ERS Standard Contract Term, a QSE may increase the number of sites in an aggregated ERS Load on a weather-sensitive baseline by no more than the greater of the following:

(i) 100% of the initial number of sites; or

(ii) Two MW times the QSE's projection of the maximum number of sites in the aggregation during the ERS Standard Contract Term, divided by the maximum MW capacity offered for any ERS Time Period for the aggregation.

(b) Any sites added to an ERS Load on a weather-sensitive baseline are subject to the same requirements for historical meter data as the other sites in the aggregation, as described in paragraph (4) of Section 8.1.3.1.1.

(16) For each of the four ERS service types, an ERS Standard Contract Term may consist of a single ERS Contract Period or multiple non-overlapping ERS Contract Periods, as follows:

(a) If no ERS Resources' obligations are exhausted for an ERS service type during an ERS Contract Period pursuant to Section 3.14.3.3, Emergency Response Service Provision and Technical Requirements, the ERS Contract Period for that ERS service type shall terminate at the end of the last Operating Day of the ERS Standard Contract Term.

(b) If one or more ERS Resources' obligations in a given ERS service type are exhausted pursuant to Section 3.14.3.3, the ERS Contract Period for that ERS service type shall terminate at the end of the Operating Day during which the exhaustion occurred. However, if ERS Resources participating in a service type remain deployed at the end of that Operating Day, the ERS Contract Period for that ERS service type shall terminate at the end of the Operating Day on which those ERS Resources are recalled.

(c) If an ERS Contract Period terminates as provided in paragraph (b) above, and one or more ERS Resources' obligations were not exhausted, a new ERS Contract Period for the ERS service type shall begin at hour ending 0100 on the following Operating Day. This new ERS Contract Period shall terminate as provided in this Section.

(d) If ERCOT elects pursuant to paragraph (b) above to renew the obligations of any ERS Resources whose obligations were entirely exhausted, a new ERS Contract Period for the ERS service type shall begin at hour ending 0100 on the Operating Day after ERCOT has notified QSEs that it has elected to renew the obligation. If a new ERS Contract Period was initiated pursuant to paragraph (c) above on an Operating Day prior to ERCOT issuing a notice of renewal under this paragraph, that ERS Contract Period shall terminate at the end of the Operating Day on which ERCOT notified QSEs that the renewal will take place. This new ERS Contract Period shall terminate as provided in this Section.

(17) An ERS Resource currently obligated to provide an ERS service type during an ERS Time Period and ERS Contract Period may be offered to provide service as an MRA during that same ERS Time Period in the ERS Contract Period. If the ERS Resource is selected to provide service as an MRA during an ERS Time Period in the ERS Contract Period in which it is currently obligated to provide an ERS service type, the ERS Contract Period will be terminated for that ERS service type. The ERS Contract Period for that ERS service type shall terminate at the end of the Operating Day that is five days before the first Operating Day the ERS Resource is obligated to provide service under the MRA Agreement. However, if any ERS Resources participating in that ERS service type are currently deployed at the end of the Operating Day the ERS Contract Period is scheduled to terminate, then the ERS Resource's ERS Contract Period for that ERS service type shall continue until the end of the Operating Day on which all of the ERS Resources participating in that ERS service type have been recalled, at which time the ERS Contract Period will terminate.

(18) ERS Resources shall be obligated in ERS Contract Periods as follows:

(a) Unless an ERS Contract Period is terminated pursuant to paragraph (17) above, for the first ERS Contract Period in an ERS Standard Contract Term, all ERS Resources awarded by ERCOT shall be obligated.

(b) ERS Resources shall be obligated for 24 hours of cumulative deployment time for any ERS Contract Period during the December through March ERS Standard Contract Term. The obligated cumulative deployment time for any ERS Contract Period during all other ERS Standard Contract Terms shall be 12 hours.