Controllable Load Resources with RTM Energy Bids at various pricing points, not taking into consideration any physical limitations of the ERCOT System;

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

[NPRR863, NPRR1007, NPRR1014, and NPRR1015: Replace applicable portions of paragraph (3) above with the following upon system implementation of NPRR863 for

NPRR863 and NPRR1015; or upon system implementation for NPRR1014; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007:]

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(i) As submitted;

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

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

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

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

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

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

(i) As submitted; and

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

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

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

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

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

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

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

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

(i) The Generation Resource name;

(ii) The Generation Resource status;

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

(iv) The Generation Resource Base Point from SCED;

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

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

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

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

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

(i) The Generation Resource name;

(ii) The Generation Resource status;

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

(iv) The Generation Resource Base Point from SCED;

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

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

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

(viii) The telemetered Normal Ramp Rates;

(ix) The telemetered Ancillary Service capabilities; and

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

(i) The Load Resource name;

(ii) The Load Resource status;

(iii) The MPC for a Load Resource;

(iv) The LPC for a Load Resource;

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

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

(vii) The telemetered real power consumption; and

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

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

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

(i) The Load Resource name;

(ii) The Load Resource status;

(iii) The MPC for a Load Resource;

(iv) The LPC for a Load Resource;

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

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

(vii) The telemetered real power consumption;

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

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

(x) The telemetered Normal Ramp Rates;

(xi) The telemetered Ancillary Service capabilities; and

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

(i) As submitted; and

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

(k) The following ESR data using a snapshot from each execution of SCED:

(i) The ESR name;

(ii) The ESR status;

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

(iv) The ESR Base Point from SCED;

(v) The telemetered ESR net output used in SCED;

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

(vii) The telemetered Normal Ramp Rates;

(viii) The telemetered Ancillary Service capabilities; and

(ix) The telemetered State of Charge in MWh.

[NPRR1007 and NPRR1058: Insert applicable portions of paragraph (5) below upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1058; and renumber accordingly:]

(5) ERCOT shall post on the ERCOT website for each Resource for each Operating Hour 60 days prior to the current Operating Day a count of the number of times for each Ancillary Service that the Resource's Ancillary Service Offer quantity or price was updated within the Operating Period. ERCOT shall post on the ERCOT website for each Resource for each Operating Hour 60 days prior to the current Operating Day, a count of the number of times a Resource's Energy Offer quantity or price was updated within the Operating Hour, including any reason accompanying the update.

(5) If any Real-Time Locational Marginal Price (LMP) exceeds 50 times the Fuel Index Price (FIP) during any 15-minute Settlement Interval for the applicable Operating Day, ERCOT shall post on the ERCOT website the portion of any Generation Resource's as-submitted and as-mitigated and extended Energy Offer Curve that is at or above 50 times the FIP for each 15-minute Settlement Interval seven days after the applicable Operating Day.

[NPRR1007 and NPRR1014: Replace applicable portions of paragraph (5) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014:]

(6) If any Real-Time Locational Marginal Price (LMP) exceeds 50 times the Fuel Index Price (FIP) during any SCED interval for the applicable Operating Day, ERCOT shall post on the ERCOT website the portion of any Generation Resource's as-submitted and as-mitigated and extended Energy Offer Curve or any ESR's as-submitted and as-mitigated and extended Energy Bid/Offer Curve that is at or above 50 times the FIP for that SCED interval seven days after the applicable Operating Day.

(6) If any Market Clearing Price for Capacity (MCPC) for an Ancillary Service exceeds 50 times the FIP for any Operating Hour in a DAM or Supplemental Ancillary Services Market (SASM) for the applicable Operating Day, ERCOT shall post on the ERCOT website the portion on any Resource's Ancillary Service Offer that is at or above 50 times the FIP for that Ancillary Service for each Operating Hour seven days after the applicable Operating Day.

[NPRR1007 and NPRR1014: Replace applicable portions of paragraph (6) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014:]

(7) If any Market Clearing Price for Capacity (MCPC) for an Ancillary Service exceeds 50 times the FIP for any Operating Hour in a DAM or any SCED interval in the RTM for the applicable Operating Day, ERCOT shall post on the ERCOT website the portion on any Resource's Ancillary Service Offer that is at or above 50 times the FIP for that Ancillary Service for that Operating Hour for the DAM or SCED interval for the RTM seven days after the applicable Operating Day.

(7) ERCOT shall post on the ERCOT website the offer price and the name of the Entity submitting the offer for the highest-priced offer selected or Dispatched by SCED three days after the end of the applicable Operating Day. If multiple Entities submitted the highest-priced offers selected, all Entities shall be identified on the ERCOT website.

(8) ERCOT shall post on the ERCOT website the bid price and the name of the Entity submitting the bid for the highest-priced bid selected or Dispatched by SCED three days after the end of the applicable Operating Day. If multiple Entities submitted the highest-priced bids selected, all Entities shall be identified on the ERCOT website.

(9) ERCOT shall post on the ERCOT website the offer price and the name of the Entity submitting the offer for the highest-priced Ancillary Service Offer selected in the DAM for each Ancillary Service three days after the end of the applicable Operating Day. This same report shall also include the highest-priced Ancillary Service Offer selected for any SASMs cleared for that same Operating Day. If multiple Entities submitted the highest-priced offers selected, all Entities shall be identified on the ERCOT website. The report shall specify whether the Ancillary Service Offer was selected in a DAM or a SASM.

[NPRR1007 and NPRR1014: Replace applicable portions of paragraph (9) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014:]

(10) ERCOT shall post on the ERCOT website the offer price and the name of the Entity submitting the offer for the highest-priced Ancillary Service Offer selected in the DAM or RTM for each Ancillary Service three days after the end of the applicable Operating Day. If multiple Entities submitted the highest-priced offers selected, all Entities shall be identified on the ERCOT website. The report shall specify whether the Ancillary Service Offer was selected in a DAM or RTM.

(10) ERCOT shall post on the ERCOT website for each Operating Day the following information for each Resource:

(a) The Resource name;

(b) The name of the Resource Entity;

(c) Except for Load Resources that are not SCED qualified, the name of the Decision Making Entity (DME) controlling the Resource, as reflected in the Managed Capacity Declaration submitted by the Resource Entity in accordance with Section 3.6.2, Decision Making Entity for a Resource; and

(d) Flag for Reliability Must-Run (RMR) Resources.

(11) ERCOT shall post on the ERCOT website the following information from the DAM for each hourly Settlement Interval for the applicable Operating Day 60 days prior to the current Operating Day:

(a) The Generation Resource name and the Generation Resource's Three-Part Supply Offer (prices and quantities), including Startup Offer and Minimum-Energy Offer, available for the DAM;

(b) For each Settlement Point, individual DAM Energy-Only Offer Curves available for the DAM and the name of the QSE submitting the offer;

(c) The Resource name and the Resource's Ancillary Service Offers available for the DAM;

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

(d) The Ancillary Service Only Offer for each Ancillary Service and the name of the QSE submitting the offer;

(d) For each Settlement Point, individual DAM Energy Bids available for the DAM and the name of the QSE submitting the bid;

(e) For each Settlement Point, individual PTP Obligation bids available to the DAM that sink at the Settlement Point and the QSE submitting the bid;

(f) The awards for each Ancillary Service from DAM for each Generation Resource;

(g) The awards for each Ancillary Service from DAM for each Load Resource;

(h) The award of each Three-Part Supply Offer from the DAM and the name of the QSE receiving the award;

(i) For each Settlement Point, the award of each DAM Energy-Only Offer from the DAM and the name of the QSE receiving the award;

(j) For each Settlement Point, the award of each DAM Energy Bid from the DAM and the name of the QSE receiving the award; and

(k) For each Settlement Point, the award of each PTP Obligation bid from the DAM that sinks at the Settlement Point, including whether or not the PTP Obligation bid was linked to an Option, and the QSE submitting the bid.

[NPRR1014: Insert items (m)-(o) below upon system implementation:]

(m) The ESR name and the ESR's Energy Bid/Offer Curve (prices and quantities), available for the DAM;

(n) The awards for each Ancillary Service from the DAM for each ESR; and

(o) The award of each Energy Bid/Offer Curve from the DAM and the name of the QSE receiving the award.

(12) ERCOT shall post on the ERCOT website the following information from any applicable SASMs for each hourly Settlement Interval for the applicable Operating Day 60 days prior to the current Operating Day:

(a) The Resource name and the Resource's Ancillary Service Offers available for any applicable SASMs;

(b) The awards for each Ancillary Service from any applicable SASMs for each Generation Resource; and

(c) The awards for each Ancillary Service from any applicable SASMs for each Load Resource.

[NPRR1007: Delete paragraph (12) above upon system implementation of the Real-Time Co-Optimization (RTC) project.]

3.2.5.1 Unregistered Distributed Generation Reporting Requirements for Non Opt-In Entities

(1) This Section describes the data that shall be submitted to ERCOT for the unregistered Distributed Generation (DG) behind Non-Opt-In Entity (NOIE) boundary metering points.

(2) Within ten Business Days after the end of each quarter, each NOIE shall submit to ERCOT electronically the required data described below as of the last day of the prior quarter by submitting the designated form provided on the ERCOT website. NOIEs that have an unregistered DG capacity of more than two MW, based upon the aggregate capacity of all sites that are less than 50 kW, shall report the total of all unregistered DG

MW capacity, inclusive of systems used to support self-serve Load. All other NOIEs shall report the aggregate unregistered DG capacity of only those sites greater than or equal to 50 kW, inclusive of systems used to support self-serve Load. NOIEs shall report their capacity by Load Zone and by primary fuel type as follows:

(a) Solar;

(b) Wind;

(c) Other renewable; and

(d) Other non-renewable.

(3) NOIEs not reporting DG MW capacity less than 50 kW on a quarterly basis as described in paragraph (2) above shall submit to ERCOT by March 1 of each year their annual aggregate unregistered DG MW capacity, inclusive of systems used to support self-serve Load, for the preceding calendar year. NOIEs shall report their capacity by Load Zone and by primary fuel type as follows:

(a) Solar;

(b) Wind;

(c) Other renewable; and

(d) Other non-renewable.

(4) Each of the above reports is required to include only the capacity known to the NOIE at the time that its report is being prepared, and shall not require the NOIE to conduct new survey activities for its service territory to identify unknown unregistered DG installations. Any NOIE may obtain a reporting exemption for the annual report required in 2020 by notifying ERCOT of the exemption claim in writing on or before March 1, 2020.

3.2.5.2 Unregistered Distributed Generation Reporting Requirements for Competitive Areas

(1) The data for competitive areas will be compiled from the reports submitted to ERCOT as found in the Load Profiling Guide, Appendix D, Load Profiling Decision Tree, DG Tab.

3.2.5.3 Unregistered Distributed Generation Reporting Requirements for ERCOT

(1) Within 30 days after the end of each quarter, ERCOT shall publish the unregistered DG report on the ERCOT website. This report shall include the aggregated data compiled for NOIE and competitive areas. This report shall include the total unregistered DG MW capacity, as provided in accordance with Section 3.2.5.1, Unregistered Distributed

Generation Reporting Requirements for Non Opt-In Entities, and Section 3.2.5.2, Unregistered Distributed Generation Reporting Requirements for Competitive Areas, above, by Load Zone and by primary fuel type as follows:

(a) Solar;

(b) Wind;

(c) Other renewable; and

(d) Other non-renewable.

(2) ERCOT shall update the appropriate TAC subcommittee on an as needed basis on the unregistered DG report.

3.2.6 ERCOT Planning Reserve Margin

(1) ERCOT shall calculate the Planning Reserve Margin (PRM) for each Peak Load Season as follows:

$$\mathbf{PRM}_{s,\,i} = (\mathbf{TOTCAP}_{s,\,i} - \mathbf{FIRMPKLD}_{s,\,i}) \,/\, \mathbf{FIRMPKLD}_{s,\,i}$$

The above variables are defined as follows:

Variable	Unit	Definition
$PRM_{s,\,i}$	%	*Planning Reserve Margin*—The Planning Reserve Margin for the Peak Load Season *s* for year *i*.
$TOTCAP_{s,\,i}$	MW	*Total Capacity*—Total Capacity available during the Peak Load Season *s* for the year *i*.
$FIRMPKLD_{s,\,i}$	MW	*Firm Peak Load*—Firm Peak Load for the Peak Load Season *s* for the year *i*.
i	None	Year.
s	None	Peak Load Season.

3.2.6.1 Minimum ERCOT Planning Reserve Margin Criterion

(1) The minimum ERCOT PRM criterion is approved by the ERCOT Board. ERCOT shall periodically review and recommend to the ERCOT Board any changes to the minimum ERCOT PRM to help ensure adequate reliability of the ERCOT System. ERCOT shall update the minimum PRM on the first day of the month following ERCOT Board approval unless otherwise directed by the ERCOT Board. ERCOT shall post the revised minimum PRM to the ERCOT website prior to implementation.

3.2.6.2 ERCOT Planning Reserve Margin Calculation Methodology

(1) ERCOT shall prepare and publish on the ERCOT website, at least annually, the Report on Capacity, Demand and Reserves in the ERCOT Region containing an estimate of the

PRM for the current Peak Load Seasons as well as a minimum of ten future summer and winter peak Load periods. The format and content of this report shall be developed by ERCOT, and subject to TAC approval. The estimate of the PRM shall be based on the methodology in Section 3.2.6.2.1, Peak Load Estimate, and Section 3.2.6.2.2, Total Capacity Estimate.

(2) ERCOT shall prepare and publish on the ERCOT website, no later than 60 days after the end of each summer and winter Peak Load Season, updates to the variable WINDPEAKPCT, defined in Section 3.2.6.2.2. The published information will also include the following inputs and associated formulas used in the variable calculations:

(a) The date, hour, and associated Load for the 20 highest system-wide peak Load hours by region, season and year;

(b) The wind capacity for the 20 highest system-wide peak Load hours by region, season and year; and

(c) The installed wind capacity by region and year.

3.2.6.2.1 Peak Load Estimate

(1) ERCOT shall prepare, at least annually, a forecast of the total peak Load for both summer and winter Peak Load Seasons for the current year and a minimum of ten future years using an econometric forecast, taking into account econometric inputs, weather conditions, demographic data and other variables as deemed appropriate by ERCOT. The firm Peak Load Season estimate shall be determined by the following equation:

$$\textbf{FIRMPKLD}_{s,\,i} = \textbf{TOTPKLD}_{s,\,i} - \textbf{LRRRS}_{s,\,i} - \textbf{LRNSRS}_{s,\,i} - \textbf{ERS}_{s,\,i} - \textbf{CLR}_{s,\,i} - \textbf{ENERGYEFF}_{s,\,i}$$

[NPRR863: Replace the formula "FIRMPKLD $_{s,\,i}$" above with the following upon system implementation:]

$$\textbf{FIRMPKLD}_{s,\,i} = \textbf{TOTPKLD}_{s,\,i} - \textbf{LRRRS}_{s,\,i} - \textbf{LRECRS}_{s,\,i} - \textbf{LRNSRS}_{s,\,i} - \textbf{ERS}_{s,\,i} - \textbf{CLR}_{s,\,i} - \textbf{ENERGYEFF}_{s,\,i}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
FIRMPKLD $_{s,\,i}$	MW	*Firm Peak Load Estimate*—The Firm Peak Load Estimate for the Peak Load Season *s* for the year *i*.
TOTPKLD $_{s,\,i}$	MW	*Total Peak Load Estimate*—The Total Peak Load Estimate for the Peak Load Season *s* for the year *i*.
LRRRS $_{s,\,i}$	MW	*Load Resource providing RRS*—The amount of RRS a Load Resource is providing for the Peak Load Season *s* for the year *i*.

[NPRR863: Insert the variable "LRECRS $_{s,\,i}$" below upon system implementation:]

LRECRS $_{s,\,i}$	MW	*Load Resource providing ECRS*—The amount of ECRS a Load Resource is providing for the Peak Load Season *s* for the year *i*.

<table>
<tr><td>LRNSRS $_{s,\,i}$</td><td>MW</td><td>Load Resource providing Non-Spinning Reserve (Non-Spin)—The estimated amount of Non-Spin that Load Resources are providing for the Peak Load Season s for the year i.</td></tr>
<tr><td>ERS $_{s,\,i}$</td><td>MW</td><td>Emergency Response Service (ERS)—The estimated amount of ERS for the Peak Load Season s for the year i calculated as follows:
<table>
<tr><th>Year (i)</th><th>Winter Peak Load</th><th>Summer Peak Load</th></tr>
<tr><td>Current Year (i = 1)</td><td>The simple average of the amount of ERS procured by ERCOT for the current year Standard Contract Term of December 1 to March 31 for the ERS Time Periods covering all or any part of Hour Ending 0600 and Hour Ending 1800.</td><td>The amount of ERS procured by ERCOT for the current year Standard Contract Term of June 1 through September 30 for an ERS Time Period covering all or any part of Hour Ending 1800.</td></tr>
<tr><td>Second Year (i = 2)</td><td>The current year Winter Peak Load ERS amount escalated by the compound annual growth rate of the three Winter Peak Load ERS amounts preceding the current year.</td><td>The current year Summer Peak Load ERS amount escalated by the compound annual growth rate of the three Summer Peak Load ERS amounts preceding the current period.</td></tr>
<tr><td>Third Year (i = 3)</td><td>The second year Winter Peak Load ERS amount escalated by the compound annual growth rate of the three Winter Peak Load ERS amounts preceding the current year.</td><td>The second year Summer Peak Load ERS amount escalated by the compound annual growth rate of the three Summer Peak Load ERS amounts preceding the current year.</td></tr>
<tr><td>Years after Third Year (i > 3)</td><td>Equal to third year amount.</td><td>Equal to third year amount.</td></tr>
</table></td></tr>
<tr><td>CLR $_{s,\,i}$</td><td>MW</td><td>Amount of Controllable Load Resource—Estimated amount of Controllable Load Resource that is available for Dispatch by ERCOT during the current year i for the Peak Load Season s not already included in LRRRS or LRNSRS. This value does not include Wholesale Storage Load (WSL).

[NPRR863: Insert the definition above with the following upon system implementation:]

Amount of Controllable Load Resource—Estimated amount of Controllable Load Resource that is available for Dispatch by ERCOT during the current year i for the Peak Load Season s not already included in LRRRS, LRECRS, or LRNSRS. This value does not include Wholesale Storage Load (WSL).</td></tr>
</table>

$\text{ENERGYEFF}_{s,\,i}$	MW	*Amount of Energy Efficiency Programs Procured*—Estimated amount of energy efficiency programs procured by Transmission and/or Distribution Service Providers (TDSPs) pursuant to P.U.C. SUBST. R. 25.181, Energy Efficiency Goal, for the Peak Load Season *s* for the year *i*. ERCOT may also consider any energy efficiency and/or Demand response initiatives reported by NOIEs.
i	None	Year.
s	None	Peak Load Season.

3.2.6.2.2 Total Capacity Estimate

(1) The total capacity estimate shall be determined based on the following equation:

$$\mathbf{TOTCAP}_{s,i} = \mathbf{INSTCAP}_{s,i} + \mathbf{PUNCAP}_{s,i} + \mathbf{WINDCAP}_{s,i,r} + \mathbf{HYDROCAP}_{s,i} + \mathbf{SOLARCAP}_{s,i} + \mathbf{RMRCAP}_{s,i} + \mathbf{DCTIECAP}_{s} + \mathbf{PLANDCTIECAP}_{s} + \mathbf{SWITCHCAP}_{s,i} + \mathbf{MOTHCAP}_{s,i} + \mathbf{PLANNON}_{s,i} + \mathbf{PLANIRR}_{s,i,r} - \mathbf{LTOUTAGE}_{s,i} - \mathbf{UNSWITCH}_{s,i} - \mathbf{RETCAP}_{s,i}$$

The above variables are defined as follows:

Variable	Unit	Definition
$\text{TOTCAP}_{s,\,i}$	MW	*Total Capacity*—Estimated total capacity available during the Peak Load Season *s* for the year *i*.
$\text{INSTCAP}_{s,\,i}$	MW	*Seasonal Net Max Sustainable Rating*—The Seasonal net max sustainable rating for the Peak Load Season *s* as reported in the approved Resource Registration process for each operating Generation Resource for the year *i* excluding WGRs, hydro Generation Resource capacity, solar unit capacity, Resources operating under RMR Agreements, and Generation Resources capable of "switching" from the ERCOT Region to a non-ERCOT Region.
$\text{PUNCAP}_{s,\,i}$	MW	*Private Use Network Capacity*—The forecasted generation capacity available to the ERCOT Transmission Grid, net of self-serve load, from Generation Resources and Settlement Only Generators (SOGs) in Private Use Networks for Peak Load Season *s* and year *i*. The capacity forecasts are developed as follows. First, a base capacity forecast, determined from Settlement data, is calculated as the average net generation capacity available to the ERCOT Transmission Grid during the 20 highest system-wide peak Load hours for each preceding three-year period for Peak Load Season *s* and year *i*. The base capacity forecast is then adjusted by adding the aggregated incremental forecasted annual changes in net generation capacity as of the start of the summer Peak Load Season *s* for forecast year *i* reported for Private Use Networks pursuant to Section 10.3.2.4, Reporting of Net Generation Capacity. This calculation is limited to Generation Resources and SOGs in Private Use Networks (1) with a Resource Commissioning Date that occurs no later than the start of the most current Peak Load Season used for the calculation, and (2) that have not been permanently retired by the start of the most current Peak Load Season used for the calculation.

Variable	Unit	Definition
WINDPEAKPCT $_{s, r}$	%	*Seasonal Peak Average Wind Capacity as a Percent of Installed Capacity*—The average WGR capacity available for the summer and winter Peak Load Seasons *s* and region *r*, divided by the installed capacity for region *r*, expressed as a percentage. The Seasonal Peak Average, derived from Settlement data, is first calculated as the average capacity during the 20 highest system-wide peak Load hours for a given year's summer and winter Peak Load Seasons. The final value is the weighted average of the previous ten eligible years of Seasonal Peak Average values where each year is weighted by its installed capacity. Eligible years include 2009 through the most recent year for which COP data is available for the summer and winter Peak Load Seasons. If the number of eligible years is less than ten, the average shall be based on the number of eligible years available. This calculation is limited to WGRs (1) with a Resource Commissioning Date that occurs no later than the start of the most current Peak Load Season used for the calculation, and (2) that have not been permanently retired by the start of the most current Peak Load Season used for the calculation.
WINDCAP $_{s, i, r}$	MW	*Existing WGR Capacity*—The capacity available for all existing WGRs for the summer and winter Peak Load Seasons *s,* year *i*, and region *r*, multiplied by WINDPEAKPCT for summer and winter Peak Load Seasons *s* and region *r*.
HYDROCAP $_{s, i}$	MW	*Hydro Unit Capacity*—The average hydro Generation Resource capacity available, as determined from the COP, during the highest 20 peak Load hours for each preceding three-year period for Peak Load Season *s* and year *i*. This calculation is limited to hydro Generation Resources (1) with a Resource Commissioning Date that occurs no later than the start of the most current Peak Load Season used for the calculation, and (2) that have not been permanently retired by the start of the most current Peak Load Season used for the calculation.
SOLARPEAKPCT $_{s}$	%	*Seasonal Peak Average Solar Capacity as a Percent of Installed Capacity*—The average PVGR capacity available for the summer and winter Peak Load Seasons *s*, divided by the installed capacity, expressed as a percentage. The Seasonal Peak Average, derived from Settlement data, is first calculated as the average capacity during the 20 highest system-wide peak Load hours for a given year's summer and winter Peak Load Seasons. The final value is the weighted average of the previous three years of Seasonal Peak Average values where each year is weighted by its installed capacity. This calculation is limited to PVGRs (1) with a Resource Commissioning Date that occurs no later than the start of the most current Peak Load Season used for the calculation, and (2) that have not been permanently retired by the start of the most current Peak Load Season used for the calculation.
SOLARCAP $_{s, i}$	MW	*Existing PVGR Capacity*—The capacity available for all existing PVGRs for the summer and winter Peak Load Season *s* and year *i*, multiplied by SOLARPEAKPCT for summer and winter Peak Load Seasons *s*.
RMRCAP $_{s, i}$	MW	*Seasonal Net Max Sustainable Rating for Generation Resource providing RMR Service*—The Seasonal net max sustainable rating for the Peak Load Season *s* as reported in the approved Resource Registration process for each Generation Resource providing RMR Service for the year *i* until the approved exit strategy for the RMR Resource is expected to be completed.

Variable	Unit	Definition
$DCTIEPEAKPCT_{s}$	%	*Seasonal Peak Average Capacity for existing DC Tie Resources as a Percent of Installed DC Tie Capacity*—The average net emergency DC Tie imports for the summer and winter Peak Load Seasons *s*, divided by the total installed DC Tie capacity for Peak Load Seasons *s*, expressed as a percentage. The average net emergency DC Tie imports is calculated for the SCED intervals during which ERCOT declared an Energy Emergency Alert (EEA). This calculation is limited to the most recent single summer and winter Peak Load Seasons in which an EEA was declared. The total installed DC Tie capacity is the capacity amount at the start of the Peak Load Seasons used for calculating the net DC Tie imports.
$DCTIECAP_{s}$	MW	*Expected Existing DC Tie Capacity Available under Emergency Conditions*—$DCTIEPEAKPCT_{s}$ multiplied by the installed DC Tie capacity available for the summer and winter Peak Load Seasons *s*, adjusted for any known capacity transfer limitations.
$PLANDCTIECAP_{s}$	MW	*Expected Planned DC Tie Capacity Available under Emergency Conditions*—$DCTIEPEAKPCT_{s}$ multiplied by the maximum peak import capacity of planned DC Tie projects included in the most recent Steady State Working Group (SSWG) base cases, for the summer and winter Peak Load Seasons *s*. The import capacity may be adjusted to reflect known capacity transfer limitations indicated by transmission studies.
$SWITCHCAP_{s,\ i}$	MW	*Seasonal Net Max Sustainable Rating for Switchable Generation Resource*—The Seasonal net max sustainable rating for the Peak Load Season *s* as reported in the approved Resource Registration process for each Generation Resource for the year *i* that can electrically connect (i.e., “switch”) from the ERCOT Region to another power region.
$MOTHCAP_{s,\ i}$	MW	*Seasonal Net Max Sustainable Rating for Mothballed Generation Resource*—The Seasonal net max sustainable rating for the Peak Load Season *s* as reported in the approved Resource Registration process for each Mothballed Generation Resource for the year *i* based on the lead time and probability information furnished by the owners of Mothballed Generation Resources pursuant to Section 3.14.1.9, Generation Resource Status Updates. If the value furnished by the owner of a Mothballed Generation Resource pursuant to Section 3.14.1.9 is greater than or equal to 50%, then use the Seasonal net max sustainable rating for the Peak Load Season *s* as reported in the approved Resource registration process for the Mothballed Generation Resource for the year *i*. If the value furnished by the owner of a Mothballed Generation Resource pursuant to Section 3.14.1.9 is less than 50%, then exclude that Resource from the Total Capacity Estimate.

Variable	Unit	Definition
PLANNON $_{s,\,i}$	MW	*New, non-IRR Generating Capacity*—The amount of new, non-IRR generating capacity available by July 1 and December 1 for the summer and winter Peak Load Seasons *s*, respectively, and year *i* that: (a) has a Texas Commission on Environmental Quality (TCEQ)-approved air permit, (b) has a federal Greenhouse Gas permit, if required, (c) has obtained water rights, contracts or groundwater supplies sufficient for the generation of electricity at the Resource, and (d) has a signed Standard Generation Interconnection Agreement (SGIA), or a public, financially-binding agreement between the Resource owner and TSP under which generation interconnection facilities would be constructed; or for a Municipally Owned Utility (MOU) or Electric Cooperative (EC), a public commitment letter to construct a new Resource. New, non-IRR generating capacity is excluded if the Generation Interconnection or Change Request (GINR) project status in the online Resource Integration and Ongoing Operations (RIOO) interconnection services system is set to "Cancelled" or "Inactive" or if the Resource was previously mothballed or retired and does not have an owner that intends to operate it. For the purposes of this section, ownership of a mothballed or retired Resource for which a new generation interconnection is sought can only be satisfied by proof of site control as described in paragraph (1)(a), (b), or (d) of Planning Guide Section 5.3.2.1, Proof of Site Control.
PLANIRR $_{s,\,i,\,r}$	MW	*New IRR Capacity*—For new WGRs, the capacity available by July 1 and December 1 for the summer and winter Peak Load Seasons *s,* respectively, year *i*, and region *r*, multiplied by WINDPEAKPCT for summer and winter Load Season *s* and region *r*. For new PVGRs, the capacity available for the summer and winter Peak Load Seasons *s* and year *i*, multiplied by SOLARPEAKPCT for summer and winter Load Seasons *s*. New IRRs must have an SGIA or other public, financially binding agreement between the Resource owner and TSP under which generation interconnection facilities would be constructed or, for a MOU or EC, a public commitment letter to construct a new IRR. New IRR capacity is excluded if the GINR project status in the online RIOO interconnection services system is set to "Cancelled," or "Inactive."
LTOUTAGE $_{s,\,i}$	MW	*Forced Outage Capacity Reported in a Notification of Suspension of Operations*—For non-IRRs whose operation has been suspended due to a Forced Outage as reported in a Notification of Suspension of Operations (NSO), the sum of Seasonal net max sustainable ratings for Peak Load Seasons *s* for year *i*, as reported in the NSO forms. For IRRs, use the PLANIRR $_{s,\,i,\,r}$ calculated for each IRR.
UNSWITCH $_{s,\,i}$	MW	*Capacity of Unavailable Switchable Generation Resource*—The amount of capacity reported by the owners of a switchable Generation Resource that will be unavailable to ERCOT during the Peak Load Season *s* and year *i* pursuant to paragraph (2) of Section 16.5.4, Maintaining and Updating Resource Entity Information.
RETCAP $_{s,\,i}$	MW	*Capacity Pending Retirement*—The amount of capacity in Peak Load Season *s* of year *i* that is pending retirement based on information submitted on an NSO form (Section 22, Attachment E, Notification of Suspension of Operations) pursuant to Section 3.14.1.11, Budgeting Eligible Costs, but is under review by ERCOT pursuant to Section 3.14.1.2, ERCOT Evaluation Process, that has not otherwise been considered in any of the above defined categories. For Generation Resources and SOGs within Private Use Networks, the retired capacity amount is the peak average capacity contribution included in PUNCAP. For reporting of individual Generation Resources and SOGs in the Report on the Capacity, Demand and Reserves in the ERCOT Region, only the summer net max sustainable rating included in the NSO shall be disclosed.

Variable	Unit	Definition
i	None	Year.
s	None	Summer and winter Peak Load Seasons for year *i*.
r	None	Coastal, Panhandle, and Other wind regions. WGRs are classified into regions based on the county that contains their Point of Interconnection Bus (POIB). The Coastal region is defined as the following counties: Aransas, Brazoria, Calhoun, Cameron, Kenedy, Kleberg, Matagorda, Nueces, Refugio, San Patricio, and Willacy. The Panhandle region is defined as the following counties: Armstrong, Bailey, Briscoe, Carson, Castro, Childress, Cochran, Collingsworth, Crosby, Dallam, Deaf Smith, Dickens, Donley, Floyd, Gray, Hale, Hall, Hansford, Hartley, Hemphill, Hockley, Hutchinson, Lamb, Lipscomb, Lubbock, Moore, Motley, Ochiltree, Oldham, Parmer, Potter, Randall, Roberts, Sherman, Swisher, and Wheeler. The Other region consists of all other counties in the ERCOT Region.

3.3 Management of Changes to ERCOT Transmission Grid

(1) Additions and changes to the ERCOT System must be coordinated with ERCOT to accurately represent the ERCOT Transmission Grid.

3.3.1 ERCOT Approval of New or Relocated Facilities

(1) Before energizing and placing into service any new or relocated facility connected to the ERCOT Transmission Grid, a Transmission Service Provider (TSP), Qualified Scheduling Entity (QSE), or Resource Entity shall enter appropriate information in the Outage Scheduler and coordinate with, and receive written notice of approval from, ERCOT.

[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) Before energizing and placing into service any new or relocated facility connected to the ERCOT Transmission Grid, a Transmission Service Provider (TSP), Direct Current Tie Operator (DCTO), Qualified Scheduling Entity (QSE), or Resource Entity shall enter appropriate information in the Outage Scheduler and coordinate with, and receive written notice of approval from, ERCOT.

3.3.2 Types of Work Requiring ERCOT Approval

(1) Each TSP, QSE and Resource Entity shall coordinate with ERCOT the requirements of Section 3.10, Network Operations Modeling and Telemetry, the following types of work for any addition to, replacement of, or change to or removal from the ERCOT Transmission Grid:

[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, QSE, and Resource Entity shall coordinate with ERCOT the requirements of Section 3.10, Network Operations Modeling and Telemetry, the following types of work for any addition to, replacement of, or change to or removal from the ERCOT Transmission Grid:

(a) Transmission lines;

(b) Equipment including circuit breakers, transformers, disconnects, and reactive devices;

(c) Resource interconnections; and

(d) Protection and control schemes, including changes to Remedial Action Plans (RAPs), Supervisory Control and Data Acquisition (SCADA) systems, Energy Management Systems (EMSs), Automatic Generation Control (AGC), Remedial Action Schemes (RASs), or Automatic Mitigation Plans (AMPs).

3.3.2.1 Information to Be Provided to ERCOT

(1) The energization or removal of a Transmission Facility or Generation Resource in the Network Operations Model requires an entry into the Outage Scheduler by a TSP or Resource Entity. For TSP requests, the TSPs shall enter such requests in the Outage Scheduler. For Resource Entity requests, the Resource Entity shall enter such requests in the Outage Scheduler. If any changes in system topology or telemetry are expected, then the TSP or Resource Entity shall notify ERCOT in accordance with the schedule in Section 3.3.1, ERCOT Approval of New or Relocated Facilities. Information submitted pursuant to this subsection for Transmission Facilities within a Private Use Network shall not be publicly posted.

[NPRR857 and NPRR1014: Replace applicable portions of paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities for NPRR857; and upon system implementation for NPRR1014:]

(1) The energization or removal of a Transmission Facility, Generation Resource, or Energy Storage Resource (ESR) in the Network Operations Model requires an entry into the Outage Scheduler by a TSP, DCTO, or Resource Entity. For any TSP or DCTO request, the TSP or DCTO shall enter the request in the Outage Scheduler. For any Resource Entity request, the Resource Entity shall enter the request in the Outage Scheduler. If any changes in system topology or telemetry are expected, then the TSP, DCTO, or Resource Entity shall notify ERCOT in accordance with the schedule in Section 3.3.1, ERCOT Approval of New or Relocated Facilities. Information submitted pursuant to this subsection for Transmission Facilities within a Private Use Network shall not be publicly posted.

(2) If a Resource Entity within a Private Use Network is adding or removing a Transmission Facility at the Point of Interconnection (POI), it shall inform and determine with ERCOT whether any corresponding Network Operations Model updates are necessary. If ERCOT and the Resource Entity determine that updates are needed, the process set forth in paragraph (1) above shall be used to incorporate the update into the Network Operations Model. Information submitted pursuant to paragraph (1) above shall not be publicly posted.

(3) TSPs and Resource Entities shall submit any changes in system topology or telemetry in accordance with the Network Operations Model Change Request (NOMCR) process or other ERCOT-prescribed process applicable to Resource Entities and according to the requirements of Section 3.10.1, Time Line for Network Operations Model Changes. The submittal shall include the following:

(a) Proposed energize date;

(b) TSPs or Resource Entities performing work;

(c) TSPs or Resource Entities responsible for rating affected Transmission Element(s);

(d) For Resource Entities, data and information required by Section 16.5, Registration of a Resource Entity;

(e) Station identification code;

(f) Identification of existing Transmission Facilities involved and new Transmission Facilities (if any) being added or existing Transmission Facilities being permanently removed from service;

(g) Ratings of existing Transmission Facilities involved and new Transmission Facilities (if any) being added;

(h) Outages required (clearly identify each Outage if multiple Outages are required), including sequence of Outage and estimate of Outage duration;

(i) General statement of work to be completed with intermediate progress dates and events identified;

(j) SCADA modification work, including descriptions of the telemetry points or changes to existing telemetry, providing information on equipment being installed, changed, or monitored;

(k) Additional data determined by ERCOT and TSPs, or Resource Entities as needed to complete the ERCOT model representation of existing Transmission Facilities involved and new Transmission Facilities (if any) being added;

(l) Statement of completion, including:

(i) Statement to be made at the completion of each intermediate stage of project; and

(ii) Statement to be made at completion of total project.

(m) Drawings, including:

(i) Existing status;

(ii) Each intermediate stage; and

(iii) Proposed final configuration.

[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 submit any changes in system topology or telemetry in accordance with the Network Operations Model Change Request (NOMCR) process or other ERCOT-prescribed process applicable to Resource Entities

and according to the requirements of Section 3.10.1, Time Line for Network Operations Model Changes. The submittal shall include the following:

(a) Proposed energize date;

(b) TSPs, DCTOs, or Resource Entities performing work;

(c) TSPs, DCTOs, or Resource Entities responsible for rating affected Transmission Element(s);

(d) For Resource Entities, data and information required by Section 16.5, Registration of a Resource Entity;

(e) Station identification code;

(f) Identification of existing Transmission Facilities involved and new Transmission Facilities (if any) being added or existing Transmission Facilities being permanently removed from service;

(g) Ratings of existing Transmission Facilities involved and new Transmission Facilities (if any) being added;

(h) Outages required (clearly identify each Outage if multiple Outages are required), including sequence of Outage and estimate of Outage duration;

(i) General statement of work to be completed with intermediate progress dates and events identified;

(j) SCADA modification work, including descriptions of the telemetry points or changes to existing telemetry, providing information on equipment being installed, changed, or monitored;

(k) Additional data determined by ERCOT, TSPs, DCTOs, or Resource Entities as needed to complete the ERCOT model representation of existing Transmission Facilities involved and new Transmission Facilities (if any) being added;

(l) Statement of completion, including:

  (i) Statement to be made at the completion of each intermediate stage of project; and

  (ii) Statement to be made at completion of total project.

(m) Drawings, including:

  (i) Existing status;

  (ii) Each intermediate stage; and

(iii) Proposed final configuration.

3.3.2.2 Record of Approved Work

(1) ERCOT shall maintain a record of all work approved in accordance with Section 3.3, Management of Changes to ERCOT Transmission Grid, and shall publish, and update monthly, information on the MIS Secure Area regarding each new Transmission Element to be installed on the ERCOT Transmission Grid.

3.4 Load Zones

(1) ERCOT shall assign every power flow bus to a Load Zone for Day-Ahead Market (DAM) and Congestion Revenue Right (CRR) Settlement purposes. ERCOT shall calculate a Settlement Point Price for each Load Zone using the Load-weighted aggregated Shift Factors of the applicable energized power flow buses for each constraint. The Load-weighting must be determined using the Load distribution factors.

(2) ERCOT shall assign every Electrical Bus to a Load Zone for Real-Time Market (RTM) Settlement purposes. ERCOT shall calculate a Settlement Point Price for each Load Zone as the Load-weighted average of the Locational Marginal Prices (LMPs) at all Electrical Buses assigned to that Load Zone. The Load-weighting must be determined using the Load, if any, from the State Estimator at each Electrical Bus.

3.4.1 Load Zone Types

(1) The Load Zone types are:

(a) The Competitive Load Zones;

(b) The Non-Opt-In Entity (NOIE) Load Zones created pursuant to Section 3.4.3, NOIE Load Zones; and

(c) The Direct Current Tie (DC Tie) Load Zones as defined in Section 3.4.4, DC Tie Load Zones.

(2) The Competitive Load Zones are the four zones in effect during the 2003 ERCOT market unless they are changed pursuant to Section 3.4.2, Load Zone Modifications, less any Electrical Buses that are assigned to a NOIE Load Zone or a DC Tie Load Zone.

3.4.2 Load Zone Modifications

(1) Competitive Load Zones and NOIE Load Zones may be added, deleted, or changed, only when approved by the ERCOT Board, with the exception of paragraph (1)(c) of Section 3.4.3, NOIE Load Zones. Approved additions, deletions, or changes go into effect 48

months after the end of the month in which the addition, deletion, or change was approved, with the exception of paragraph (3) below. DC Tie Load Zones are not subject to these requirements.

(2) The addition of Load that is new to the ERCOT System to an existing Load Zone does not constitute a change to a Load Zone under this section. This provision includes the transfer of existing Load from a non-ERCOT Control Area into a Load Zone in the ERCOT System. Adding Load that is new to the ERCOT System to an existing Load Zone does not require ERCOT Board approval, and no notice period is required prior to adding such Load to an existing Load Zone.

(3) A NOIE that was included in the establishment of an automatic pre-assigned NOIE Load Zone under paragraph (1)(c) of Section 3.4.3 may elect to be assigned to an appropriate Competitive Load Zone after giving notice of termination of its power supply arrangement if a request to be assigned to a Competitive Load Zone was given to ERCOT at least 90 days prior to the start of the Pre-Assigned Congestion Revenue Right (PCRR) nomination window for the effective year of the Load Zone change. The move to a Competitive Load Zone requires ERCOT Board approval and shall be effective no sooner than the first day of the PCRR Nomination Year.

3.4.3 NOIE Load Zones

(1) The descriptions and conditions set forth below apply to Load Zones established by NOIEs:

(a) There are four NOIE Load Zones that were approved prior to the Texas Nodal Market Implementation Date: Austin Energy, City Public Service, Rayburn Country Electric Cooperative, and Lower Colorado River Authority (LCRA);

(b) Any costs allocated based upon a zonal Load Ratio Share (LRS) must be allocated using "Cost-Allocation Load Zones," which are the four Load Zones in effect during the 2003 ERCOT market unless they are changed pursuant to Section 3.4.2, Load Zone Modifications. For these allocation purposes, any NOIE Load Zone is considered to be located entirely within the 2003 ERCOT Congestion Management Zone (CMZ) that represented the largest Load for that NOIE or group of NOIEs in 2003;

(c) A separate NOIE Load Zone is made up of a group of NOIEs that are parties to the same pre-1999 power supply arrangements and that had an overall 2003 peak Load in excess of 2,300 MW. A NOIE that is a member of this separate NOIE Load Zone and that has given notice of termination of its pre-1999 power supply arrangement may elect to be assigned to an appropriate Competitive Load Zone. Such an election shall be subject to the approval process in Section 3.4.2;

(d) NOIEs may participate in only one NOIE Load Zone, and all Loads served by that NOIE must be contained within that Load Zone;

(e) Except as specified otherwise in this subsection, Load Zones established by NOIEs will be treated the same as other Load Zones, including a 48-month notice requirement for ERCOT Board approval of any changes to Load Zones. However, the addition of Load that is new to the ERCOT System, including the transfer of existing Load from a non-ERCOT Control Area, into an existing NOIE Load Zone is not a change to a Load Zone under these Protocols; and

(f) Four years after a NOIE offers its Customers retail choice, the NOIE's Load must be merged into the appropriate Competitive Load Zone(s). For a Load Zone that is an aggregation of NOIE systems of which less than all of the NOIEs opt into Customer Choice, each remaining NOIE in that NOIE Load Zone may choose to have its Load merged into the appropriate Competitive Load Zone(s) under the same four-year time frame.

3.4.4 DC Tie Load Zones

(1) A DC Tie Load Zone contains only the Electrical Bus in the ERCOT Transmission Grid that connects the DC Tie and is used in the settlement of the DC Tie Load in that zone.

3.4.5 Additional Load Buses

(1) ERCOT shall assign new Electrical Buses to a Load Zone and Cost Allocation Zone in accordance with the following rules; changes are effective immediately:

(a) For each new Electrical Bus serving Load of a NOIE that is a part of a NOIE Load Zone, the new Electrical Bus will be assigned to that NOIE Load Zone;

(b) For each new Electrical Bus not covered in paragraph (a) above, connected via Transmission Facilities to Electrical Buses all located within the same Competitive Load Zone, the new Electrical Bus will be assigned to that Competitive Load Zone;

(c) For each new Electrical Bus not covered in paragraphs (a) or (b) above, ERCOT shall simulate LMPs for the annual peak hour of the system with the new Electrical Bus incorporated into the model. ERCOT shall assign that new Electrical Bus to the Competitive Load Zone with the closest matching zonal Settlement Point Price to the new Electrical Bus's LMP;

(d) For each new Electrical Bus covered in paragraph (a) above and connected via Transmission Facilities to Electrical Buses all located within the same Cost Allocation Zone, then the new Electrical Bus will be assigned to that Cost Allocation Zone;

(e) For each new Electrical Bus covered in paragraph (a) above and not covered in paragraph (d) above, ERCOT shall simulate LMPs for the annual peak hour of the system with the new Electrical Bus incorporated into the model. ERCOT shall assign each new Electrical Bus associated with a NOIE that is a part of a NOIE

Load Zone to the Cost Allocation Zone with the closest matching zonal Settlement Point Price to the new Electrical Bus's LMP.

(f) For each new Electrical Bus not covered in paragraph (a), the new Electrical Bus is assigned to the same Cost Allocation Zone as its designated Load Zone;

3.5 Hubs

3.5.1 Process for Defining Hubs

(1) Hubs settled through ERCOT may only be created by an amendment to Section 3.5.2, Hub Definitions. Hubs are made up of one or more Electrical Buses. ERCOT shall post the list of Electrical Buses (including their names) that are part of a Hub on the ERCOT website. A Hub, once defined, may not be modified except as explicitly described in the definition of that Hub.

(2) When any Electrical Bus within a Hub Bus is added to the Network Operations Model or the Congestion Revenue Right (CRR) Network Model through changes to the Network Operations Model or CRR Network Model, ERCOT shall provide notice to all Market Participants as soon as practicable and include that Electrical Bus in the Hub Bus price calculation.

(3) When any Electrical Bus within a Hub Bus is disconnected from the Network Operations Model or the CRR Network Model through operations changes in transmission topology temporarily, ERCOT shall provide notice to all Market Participants as soon as practicable and exclude that Electrical Bus from the Hub Bus price calculation.

(4) In the event of a permanent change that removes the Hub Bus from the ERCOT Transmission Grid, ERCOT shall file a Nodal Protocol Revision Request (NPRR) to revise the appropriate Hub definition.

(5) If a Transmission Service Provider (TSP) or ERCOT plans a nomenclature change in the Network Operations Model or the CRR Network Model, ERCOT shall file a NPRR to include the nomenclature change in the Hub Bus definitions before implementing the name change to either the Network Operations Model or the CRR Network Model.

[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) If a Transmission Service Provider (TSP), Direct Current Tie Operator (DCTO), or ERCOT plans a nomenclature change in the Network Operations Model or the CRR

Network Model, ERCOT shall file a NPRR to include the nomenclature change in the Hub Bus definitions before implementing the name change to either the Network Operations Model or the CRR Network Model.

3.5.2 Hub Definitions

3.5.2.1 North 345 kV Hub (North 345)

(1) The North 345 kV Hub is composed of the following Hub Buses:

	ERCOT Operations		
No.	Hub Bus	kV	Hub
1	ANASW	345	NORTH
2	CN345	345	NORTH
3	WLSH	345	NORTH
4	FMRVL	345	NORTH
5	LPCCS	345	NORTH
6	MNSES	345	NORTH
7	PRSSW	345	NORTH
8	SSPSW	345	NORTH
9	VLSES	345	NORTH
10	ALNSW	345	NORTH
11	ALLNC	345	NORTH
12	BNDVS	345	NORTH
13	BNBSW	345	NORTH
14	BBSES	345	NORTH
15	BOSQUESW	345	NORTH
16	CDHSW	345	NORTH
17	CNTRY	345	NORTH
18	CRLNW	345	NORTH
19	CMNSW	345	NORTH
20	CNRSW	345	NORTH
21	CRTLD	345	NORTH
22	DCSES	345	NORTH
23	EMSES	345	NORTH
24	ELKTN	345	NORTH
25	ELMOT	345	NORTH
26	EVRSW	345	NORTH
27	KWASS	345	NORTH
28	FGRSW	345	NORTH
29	FORSW	345	NORTH
30	FRNYPP	345	NORTH
31	GIBCRK	345	NORTH

No.	ERCOT Operations Hub Bus	kV	Hub
32	HKBRY	345	NORTH
33	VLYRN	345	NORTH
34	JEWET	345	NORTH
35	KNEDL	345	NORTH
36	KLNSW	345	NORTH
37	LCSES	345	NORTH
38	LIGSW	345	NORTH
39	LEG	345	NORTH
40	LFKSW	345	NORTH
41	LWSSW	345	NORTH
42	MLSES	345	NORTH
43	MCCREE	345	NORTH
44	MDANP	345	NORTH
45	ENTPR	345	NORTH
46	NCDSE	345	NORTH
47	NORSW	345	NORTH
48	NUCOR	345	NORTH
49	PKRSW	345	NORTH
50	KMCHI	345	NORTH
51	PTENN	345	NORTH
52	RENSW	345	NORTH
53	RCHBR	345	NORTH
54	RNKSW	345	NORTH
55	RKCRK	345	NORTH
56	RYSSW	345	NORTH
57	SGVSW	345	NORTH
58	SHBSW	345	NORTH
59	SHRSW	345	NORTH
60	SCSES	345	NORTH
61	SYCRK	345	NORTH
62	THSES	345	NORTH
63	TMPSW	345	NORTH
64	TNP_ONE	345	NORTH
65	TRCNR	345	NORTH
66	TRSES	345	NORTH
67	TOKSW	345	NORTH
68	VENSW	345	NORTH
69	WLVEE	345	NORTH
70	W_DENT	345	NORTH
71	WTRML	345	NORTH
72	WCSWS	345	NORTH
73	WEBBS	345	NORTH

No.	ERCOT Operations Hub Bus	kV	Hub
74	WHTNY	345	NORTH
75	WCPP	345	NORTH

(2) The North 345 kV Hub Price uses the aggregated Shift Factors of the Hub Buses for each hour of the Settlement Interval of the Day-Ahead Market (DAM) in the Day-Ahead and is the simple average of the time-weighted Hub Bus prices for each 15-minute Settlement Interval in Real-Time, for each Hub Bus included in this Hub.

(3) The Day-Ahead Settlement Point Price of the Hub for a given Operating Hour is calculated as follows:

$$\textbf{DASPP}_{North345} = \textbf{DASL} - \sum_{c} (\textbf{DAHUBSF}_{North345,\,c} * \textbf{DASP}_{c}), \text{ if } \textbf{HBBC}_{North345} \neq 0$$

$$\textbf{DASPP}_{North345} = \textbf{DASPP}_{ERCOT345Bus}, \text{ if } \textbf{HBBC}_{North345} = 0$$

Where:

$$\text{DAHUBSF}_{North345,\,c} = \sum_{hb} (\text{HUBDF}_{hb,\,North345,\,c} * \text{DAHBSF}_{hb,\,North345,\,c})$$

$$\text{DAHBSF}_{hb,\,North345,\,c} = \sum_{pb} (\text{HBDF}_{pb,\,hb,\,North345,\,c} * \text{DASF}_{pb,\,hb,\,North345,\,c})$$

$$\text{HUBDF}_{hb,\,North345,\,c} = \text{IF}(\text{HB}_{North345,\,c}=0,\ 0,\ 1\ /\ \text{HB}_{North345,\,c})$$

$$\text{HBDF}_{pb,\,hb,\,North345,\,c} = \text{IF}(\text{PB}_{hb,\,North345,\,c}=0,\ 0,\ 1\ /\ \text{PB}_{hb,\,North345,\,c})$$

The above variables are defined as follows:

Variable	Unit	Definition
$\text{DASPP}_{North345}$	\$/MWh	*Day-Ahead Settlement Point Price*—The DAM Settlement Point Price at the Hub, for the hour.
DASL	\$/MWh	*Day-Ahead System Lambda*—The DAM Shadow Price for the system power balance constraint for the hour.
DASP_{c}	\$/MWh	*Day-Ahead Shadow Price for a binding transmission constraint*—The DAM Shadow Price for the constraint *c* for the hour.
$\text{DAHUBSF}_{North345,c}$	none	*Day-Ahead Shift Factor of the Hub* —The DAM aggregated Shift Factor of a Hub for the constraint *c* for the hour.
$\text{DAHBSF}_{hb,North345,c}$	none	*Day-Ahead Shift Factor of the Hub Bus*—The DAM aggregated Shift Factor of a Hub Bus *hb* for the constraint *c* for the hour.
$\text{DASF}_{pb,hb,North345,c}$	none	*Day-Ahead Shift Factor of the power flow bus*—The DAM Shift Factor of a power flow bus *pb* that is a component of Hub Bus *hb* for the constraint *c* for the hour.

Variable	Unit	Definition
$\text{HUBDF}_{hb, North345,c}$	none	*Hub Distribution Factor per Hub Bus in a constraint*—The distribution factor of Hub Bus *hb* for the constraint *c* for the hour.
$\text{HBDF}_{pb, hb, North345,c}$	none	*Hub Bus Distribution Factor per power flow bus of Hub Bus in a constraint*—The distribution factor of power flow bus *pb* that is a component of Hub Bus *hb* for the constraint *c* for the hour.
pb	none	An energized power flow bus that is a component of a Hub Bus for the constraint *c*.
$\text{PB}_{hb, North345,c}$	none	The total number of energized power flow buses in Hub Bus *hb* for the constraint *c*.
hb	none	A Hub Bus that is a component of the Hub with at least one energized power flow bus for the constraint *c*.
$\text{HBBC}_{North345}$	none	The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus in base case.
$\text{HB}_{North345,c}$	none	The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus for the constraint *c*.
c	none	A DAM binding transmission constraint for the hour caused by either base case or a contingency.

(4) The Real-Time Settlement Point Price of the Hub for a given 15-minute Settlement Interval is calculated as follows:

$$\textbf{RTSPP}_{North345} = \textbf{Max [-\$251, (RTRSVPOR + RTRDP +} \sum_{hb} \textbf{(HUBDF}_{hb, North345} \textbf{ * (} \sum_{y} \textbf{(RTHBP}_{hb, North345, y} \textbf{ * TLMP}_{y}\textbf{) / (} \sum_{y} \textbf{TLMP}_{y}\textbf{))))], if HB}_{North345} \neq 0$$

$$\textbf{RTSPP}_{\textbf{North345}} = \textbf{RTSPP}_{\textbf{ERCOT345Bus}}\textbf{, if HB}_{\textbf{North345}} = 0$$

Where:

$$\text{RTRSVPOR} = \sum_{y} (\text{RNWF}_{y} * \text{RTORPA}_{y})$$

$$\text{RTRDP} = \sum_{y} (\text{RNWF}_{y} * \text{RTORDPA}_{y})$$

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

$$\text{RTHBP}_{hb, North345, y} = \sum_{b} (\text{HBDF}_{b, hb, North345} * \text{RTLMP}_{b, hb, North345, y})$$

$$\text{HUBDF}_{hb, North345} = \text{IF}(\text{HB}_{North345}=0, 0, 1 / \text{HB}_{North345})$$

$$\text{HBDF}_{b,\ hb,\ North345} = \text{IF}(\text{B}_{hb,\ North345}=0,\ 0,\ 1\ /\ \text{B}_{hb,\ North345})$$

The above variables are defined as follows:

Variable	Unit	Description
$\text{RTSPP}_{North345}$	\$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Hub, for the 15-minute Settlement Interval.
$\text{RTHBP}_{hb,\ North345,\ y}$	\$/MWh	*Real-Time Hub Bus Price at Hub Bus per Security-Constrained Economic Dispatch (SCED) interval*—The Real-Time energy price at Hub Bus *hb* for the SCED interval *y*.
RTRSVPOR	\$/MWh	*Real-Time Reserve Price for On-Line Reserves*—The Real-Time Reserve Price for On-Line Reserves for the 15-minute Settlement Interval.
RTORPA_{y}	\$/MWh	*Real-Time On-Line Reserve Price Adder per interval*—The Real-Time price adder for On-Line Reserves for the SCED interval *y*.
RTRDP	\$/MWh	*Real-Time On-Line Reliability Deployment Price*—The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that are calculated from the Real-Time On-Line Reliability Deployment Price Adder.
RTORDPA_{y}	\$/MWh	*Real-Time On-Line Reliability Deployment Price Adder*—The Real-Time price adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
RNWF_{y}	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval.
$\text{RTLMP}_{b,\ hb,\ North345,\ y}$	\$/MWh	*Real-Time Locational Marginal Price at Electrical Bus of Hub Bus per interval*—The Real-Time LMP at Electrical Bus *b* that is a component of Hub Bus *hb*, for the SCED interval *y*.
TLMP_{y}	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the 15-minute Settlement Interval
$\text{HUBDF}_{hb,\ North345}$	none	*Hub Distribution Factor per Hub Bus*—The distribution factor of Hub Bus *hb*.
$\text{HBDF}_{b,\ hb,\ North345}$	none	*Hub Bus Distribution Factor per Electrical Bus of Hub Bus*—The distribution factor of Electrical Bus *b* that is a component of Hub Bus *hb*.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.
b	none	An energized Electrical Bus that is a component of a Hub Bus.
$\text{B}_{hb,\ North345}$	none	The total number of energized Electrical Buses in Hub Bus *hb*.
hb	none	A Hub Bus that is a component of the Hub.
$\text{HB}_{North345}$	none	The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus.

[NPRR1007 and NPRR1057: Replace applicable portions of paragraph (4) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1057:]

(4) The Real-Time Settlement Point Price of the Hub for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTSPP}_{North345} = \mathbf{Max\ [-\$251,\ (RTRDP + \sum_{y} (HUBLMP}_{North345,\,y} \mathbf{*\ RNWF}_{y}\mathbf{))]}$$

Where:

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

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

The above variables are defined as follows:

Variable	Unit	Description
RTSPP $_{North345}$	\$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Hub, for the 15-minute Settlement Interval.
RTRDP	\$/MWh	*Real-Time Reliability Deployment Price for Energy* —The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that are calculated from the Real-Time Reliability Deployment Price Adder for Energy.
RTRDPA $_{y}$	\$/MWh	*Real-Time Reliability Deployment Price Adder for Energy* —The Real-Time Price Adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
RNWF $_{y}$	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval.
HUBLMP $_{North345,\,y}$	\$/MWh	*Hub Locational Marginal Price*—The Hub LMP for the Hub for the SCED Interval *y*.
TLMP $_{y}$	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the 15-minute Settlement Interval
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.

3.5.2.2 South 345 kV Hub (South 345)

(1) The South 345 kV Hub is composed of the following Hub Buses:

	ERCOT Operations		
No.	Hub Bus	kV	Hub
1	AUSTRO	345	SOUTH
2	BLESSING	345	SOUTH
3	CAGNON	345	SOUTH
4	COLETO	345	SOUTH
5	CLEASP	345	SOUTH

No.	ERCOT Operations Hub Bus	kV	Hub
6	NEDIN	345	SOUTH
7	FAYETT	345	SOUTH
8	FPPYD1	345	SOUTH
9	FPPYD2	345	SOUTH
10	GARFIE	345	SOUTH
11	GUADG	345	SOUTH
12	HAYSEN	345	SOUTH
13	HILLCTRY	345	SOUTH
14	HOLMAN	345	SOUTH
15	KENDAL	345	SOUTH
16	LA_PALMA	345	SOUTH
17	LON_HILL	345	SOUTH
18	LOSTPI	345	SOUTH
19	LYTTON_S	345	SOUTH
20	MARION	345	SOUTH
21	PAWNEE	345	SOUTH
22	RIOHONDO	345	SOUTH
23	RIONOG	345	SOUTH
24	SALEM	345	SOUTH
25	SANMIGL	345	SOUTH
26	SKYLINE	345	SOUTH
27	STP	345	SOUTH
28	CALAVERS	345	SOUTH
29	BRAUNIG	345	SOUTH
30	WHITE_PT	345	SOUTH
31	ZORN	345	SOUTH

(2) The South 345 kV Hub Price uses the aggregated Shift Factors of the Hub Buses for each hour of the Settlement Interval of the DAM in the Day-Ahead and is the simple average of the time-weighted Hub Bus prices for each 15-minute Settlement Interval in Real-Time, for each Hub Bus included in this Hub.

(3) The Day-Ahead Settlement Point Price of the Hub for a given Operating Hour is calculated as follows:

$$\mathbf{DASPP}_{\,South345} = \mathbf{DASL} - \sum_{c}(\mathbf{DAHUBSF}_{\,South345,\,c} * \mathbf{DASP}_{\,c}),\ \textbf{if HBBC}_{\,South345} \neq 0$$

$$\mathbf{DASPP}_{\,South345} = \mathbf{DASPP}_{\,ERCOT345Bus},\ \textbf{if HBBC}_{\,South345} = 0$$

Where:

$$\text{DAHUBSF}_{\,South345,\,c} = \sum_{hb}(\text{HUBDF}_{\,hb,\,South345,\,c} * \text{DAHBSF}_{\,hb,\,South345,\,c})$$

$$\text{DAHBSF}_{hb,\ South345,\ c} = \sum_{pb}(\text{HBDF}_{pb,\ hb,\ South345,\ c} * \text{DASF}_{pb,\ hb,\ South345,\ c})$$

$$\text{HUBDF}_{hb,\ South345,\ c} = \text{IF}(\text{HB}_{South345,\ c}=0,\ 0,\ 1\ /\ \text{HB}_{South345,\ c})$$

$$\text{HBDF}_{pb,\ hb,\ South345,\ c} = \text{IF}(\text{PB}_{hb,\ South345,\ c}=0,\ 0,\ 1\ /\ \text{PB}_{hb,\ South345,\ c})$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
$\text{DASPP}_{South345}$	\$/MWh	*Day-Ahead Settlement Point Price*—The DAM Settlement Point Price at the Hub, for the hour.
DASL	\$/MWh	*Day-Ahead System Lambda*—The DAM Shadow Price for the system power balance constraint for the hour.
DASP_{c}	\$/MWh	*Day-Ahead Shadow Price for a binding transmission constraint*—The DAM Shadow Price for the constraint *c* for the hour.
$\text{DAHUBSF}_{South345,c}$	none	*Day-Ahead Shift Factor of the Hub* —The DAM aggregated Shift Factor of a Hub for the constraint *c* for the hour.
$\text{DAHBSF}_{hb,South345,c}$	none	*Day-Ahead Shift Factor of the Hub Bus*—The DAM aggregated Shift Factor of a Hub Bus *hb* for the constraint *c* for the hour.
$\text{DASF}_{pb,hb,South345,c}$	none	*Day-Ahead Shift Factor of the power flow bus*—The DAM Shift Factor of a power flow bus *pb* that is a component of Hub Bus *hb* for the constraint *c* for the hour.
$\text{HUBDF}_{hb,\ South345,c}$	none	*Hub Distribution Factor per Hub Bus in a constraint*—The distribution factor of Hub Bus *hb* for the constraint *c* for the hour.
$\text{HBDF}_{pb,\ hb,\ South345,c}$	none	*Hub Bus Distribution Factor per power flow bus of Hub Bus in a constraint*—The distribution factor of power flow bus *pb* that is a component of Hub Bus *hb* for the constraint *c* for the hour.
pb	none	An energized power flow bus that is a component of a Hub Bus for the constraint *c*.
$\text{PB}_{hb,\ South345,c}$	none	The total number of energized power flow buses in Hub Bus *hb* for the constraint *c*.
hb	none	A Hub Bus that is a component of the Hub with at least one energized power flow bus for the constraint *c*.
$\text{HBBC}_{South345}$	none	The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus in base case.
$\text{HB}_{South345,c}$	none	The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus for the constraint *c*.
c	none	A DAM binding transmission constraint for the hour caused by either base case or a contingency.

(4) The Real-Time Settlement Point Price of the Hub for a given 15-minute Settlement Interval is calculated as follows:

$$\textbf{RTSPP}_{\textit{South345}} = \textbf{Max [-\$251, (RTRSVPOR + RTRDP +}$$

$$\sum_{hb} \textbf{(HUBDF}_{hb, South345} \textbf{ * (}\sum_{y} \textbf{(RTHBP}_{hb, South345, y} \textbf{ * TLMP}_{y}\textbf{)}$$
$$\textbf{/ (}\sum_{y} \textbf{TLMP}_{y}\textbf{))))], if HB}_{South345}\neq 0$$

$$\textbf{RTSPP}_{\textbf{South345}} = \textbf{RTSPP}_{\textbf{ERCOT345Bus}}\textbf{, if HB}_{\textbf{South345}}\textbf{=0}$$

Where:

$$\text{RTRSVPOR} = \sum_{y} (\text{RNWF}_{y} * \text{RTORPA}_{y})$$

$$\text{RTRDP} = \sum_{y} (\text{RNWF}_{y} * \text{RTORDPA}_{y})$$

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

$$\text{RTHBP}_{hb, South345, y} = \sum_{b} (\text{HBDF}_{b, hb, South345} * \text{RTLMP}_{b, hb, South345, y})$$

$$\text{HUBDF}_{hb, South345} = \text{IF}(\text{HB}_{South345}=0, 0, 1 / \text{HB}_{South345})$$

$$\text{HBDF}_{b, hb, South345} = \text{IF}(\text{B}_{hb, South345}=0, 0, 1 / \text{B}_{hb, South345})$$

The above variables are defined as follows:

Variable	Unit	Description
$\text{RTSPP}_{South345}$	\$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Hub, for the 15-minute Settlement Interval.
$\text{RTHBP}_{hb, South345, y}$	\$/MWh	*Real-Time Hub Bus Price at Hub Bus per SCED interval*—The Real-Time energy price at Hub Bus *hb* for the SCED interval *y*.
RTRSVPOR	\$/MWh	*Real-Time Reserve Price for On-Line Reserves*—The Real-Time Reserve Price for On-Line Reserves for the 15-minute Settlement Interval.
RTORPA_{y}	\$/MWh	*Real-Time On-Line Reserve Price Adder per interval*—The Real-Time On-Line Reserve Price Adder for the SCED interval *y*.
RTRDP	\$/MWh	*Real-Time On-Line Reliability Deployment Price*—The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that are calculated from the Real-Time On-Line Reliability Deployment Price Adder.
RTORDPA_{y}	\$/MWh	*Real-Time On-Line Reliability Deployment Price Adder* –The Real-Time price adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
RNWF_{y}	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval.
$\text{RTLMP}_{b, hb, South345, y}$	\$/MWh	*Real-Time Locational Marginal Price at Electrical Bus of Hub Bus per interval*—The Real-Time LMP at Electrical Bus *b* that is a component of Hub Bus *hb*, for the SCED interval *y*.
TLMP_{y}	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the 15-minute Settlement Interval.

$HUBDF_{hb, South345}$	none	*Hub Distribution Factor per Hub Bus*—The distribution factor of Hub Bus *hb*.
$HBDF_{b, hb, South345}$	none	*Hub Bus Distribution Factor per Electrical Bus of Hub Bus*—The distribution factor of Electrical Bus *b* that is a component of Hub Bus *hb*.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.
b	none	An energized Electrical Bus that is a component of a Hub Bus.
$B_{hb, South345}$	none	The total number of energized Electrical Buses in Hub Bus *hb*.
hb	none	A Hub Bus that is a component of the Hub.
$HB_{South345}$	none	The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus.

[NPRR1007 and NPRR1057: Replace applicable portions of paragraph (4) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1057:]

(4) The Real-Time Settlement Point Price of the Hub for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTSPP}_{South345} = \mathbf{Max\ [-\$251, (RTRDP + \sum_{y} (HUBLMP}_{South345, y} \mathbf{* RNWF}_{y}\mathbf{))]}$$

Where:

$$RTRDP = \sum_{y} (RNWF_{y} * RTRDPA_{y})$$

$$RNWF_{y} = TLMP_{y} / \sum_{y} TLMP_{y}$$

The above variables are defined as follows:

Variable	Unit	Description
$RTSPP_{South345}$	\$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Hub, for the 15-minute Settlement Interval.
RTRDP	\$/MWh	*Real-Time Reliability Deployment Price for Energy*—The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that are calculated from the Real-Time Reliability Deployment Price Adder for Energy.
$RTRDPA_{y}$	\$/MWh	*Real-Time Reliability Deployment Price Adder for Energy* –The Real-Time Price Adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
$HUBLMP_{South345, y}$	\$/MWh	*Hub Locational Marginal Price*—The Hub LMP for the Hub for the SCED Interval *y*.
$RNWF_{y}$	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval.
$TLMP_{y}$	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the 15-minute Settlement Interval.

y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.

3.5.2.3 Houston 345 kV Hub (Houston 345)

(1) The Houston 345 kV Hub is composed of the following listed Hub Buses:

No.	ERCOT Operations Hub Bus	kV	Hub
1	ADK	345	HOUSTON
2	BI	345	HOUSTON
3	CBY	345	HOUSTON
4	CTR	345	HOUSTON
5	CHB	345	HOUSTON
6	DPW	345	HOUSTON
7	DOW	345	HOUSTON
8	RNS	345	HOUSTON
9	GBY	345	HOUSTON
10	JN	345	HOUSTON
11	KG	345	HOUSTON
12	KDL	345	HOUSTON
13	NB	345	HOUSTON
14	OB	345	HOUSTON
15	PHR	345	HOUSTON
16	SDN	345	HOUSTON
17	SMITHERS	345	HOUSTON
18	THW	345	HOUSTON
19	WAP	345	HOUSTON
20	WO	345	HOUSTON

(2) The Houston 345 kV Hub Price uses the aggregated Shift Factors of the Hub Buses for each hour of the Settlement Interval of the DAM in the Day-Ahead and is the simple average of the time-weighted Hub Bus prices for each 15-minute Settlement Interval in Real-Time, for each Hub Bus included in this Hub.

(3) The Day-Ahead Settlement Point Price of the Hub for a given Operating Hour is calculated as follows:

$$\mathbf{DASPP}_{\mathit{Houston345}} = \mathbf{DASL} - \sum_{c}(\mathbf{DAHUBSF}_{\mathit{Houston345,\,c}} * \mathbf{DASP}_{\mathit{c}}),\ \text{if } \mathbf{HBBC}_{\mathit{Houston345}} \neq 0$$

$$\mathbf{DASPP}_{\mathit{Houston345}} = \mathbf{DASPP}_{\mathit{ERCOT345Bus}},\ \text{if } \mathbf{HBBC}_{\mathit{Houston345}} = 0$$

Where:

$$\text{DAHUBSF}_{\,Houston345,\,c} = \sum_{hb} (\text{HUBDF}_{\,hb,\,Houston345,\,c} * \text{DAHBSF}_{\,hb,\,Houston345,\,c})$$

$$\text{DAHBSF}_{\,hb,\,Houston345,\,c} = \sum_{pb} (\text{HBDF}_{\,pb,\,hb,\,Houston345,\,c} * \text{DASF}_{\,pb,\,hb,\,Houston345,\,c})$$

$$\text{HUBDF}_{\,hb,\,Houston345,\,c} = \text{IF}(\text{HB}_{\,Houston345,\,c}{=}0,\ 0,\ 1\ /\ \text{HB}_{\,Houston345,\,c})$$

$$\text{HBDF}_{\,pb,\,hb,\,Houston345,\,c} = \text{IF}(\text{PB}_{\,hb,\,Houston345,\,c}{=}0,\ 0,\ 1\ /\ \text{PB}_{\,hb,\,Houston345,\,c})$$

The above variables are defined as follows:

Variable	Unit	Definition
DASPP $_{Houston345}$	\$/MWh	*Day-Ahead Settlement Point Price*—The DAM Settlement Point Price at the Hub, for the hour.
DASL	\$/MWh	*Day-Ahead System Lambda*—The DAM Shadow Price for the system power balance constraint for the hour.
DASP $_{c}$	\$/MWh	*Day-Ahead Shadow Price for a binding transmission constraint*—The DAM Shadow Price for the constraint *c* for the hour.
DAHUBSF $_{Houston345,c}$	none	*Day-Ahead Shift Factor of the Hub* —The DAM aggregated Shift Factor of a Hub for the constraint *c* for the hour.
DAHBSF $_{hb,Houston345,c}$	none	*Day-Ahead Shift Factor of the Hub Bus*—The DAM aggregated Shift Factor of a Hub Bus *hb* for the constraint *c* for the hour.
DASF $_{pb,hb,Houston345,c}$	none	*Day-Ahead Shift Factor of the power flow bus*—The DAM Shift Factor of a power flow bus *pb* that is a component of Hub Bus *hb* for the constraint *c* for the hour.
HUBDF $_{hb, Houston345,c}$	none	*Hub Distribution Factor per Hub Bus in a constraint*—The distribution factor of Hub Bus *hb* for the constraint *c* for the hour.
HBDF $_{pb, hb, Houston345,c}$	none	*Hub Bus Distribution Factor per power flow bus of Hub Bus in a constraint*—The distribution factor of power flow bus *pb* that is a component of Hub Bus *hb* for the constraint *c* for the hour.
pb	none	An energized power flow bus that is a component of a Hub Bus for the constraint *c*.
PB $_{hb, Houston345,c}$	none	The total number of energized power flow buses in Hub Bus *hb* for the constraint *c*.
hb	none	A Hub Bus that is a component of the Hub with at least one energized power flow bus for the constraint *c*.
HBBC $_{Houston345}$	none	The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus in base case.
HB $_{Houston345,c}$	none	The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus for the constraint *c*.
c	none	A DAM binding transmission constraint for the hour caused by either base case or a contingency.

(4) The Real-Time Settlement Point Price of the Hub for a given 15-minute Settlement Interval is calculated as follows:

RTSPP $_{\boldsymbol{Houston345}}$ **= Max [-\$251, (RTRSVPOR + RTRDP +**

$$\sum_{hb} \textbf{(HUBDF}_{\textit{hb, Houston345}} \textbf{* (}\sum_{y} \textbf{(RTHBP}_{\textit{hb, Houston345, y}} \textbf{*}$$

$$\textbf{TLMP}_{y}\textbf{) / (}\sum_{y} \textbf{TLMP}_{y}\textbf{))))], if HB}_{\textit{Houston345}}\neq \textbf{0}$$

$$\textbf{RTSPP}_{\textbf{Houston345}} = \textbf{RTSPP}_{\textbf{ERCOT345Bus}}\textbf{, if HB}_{\textbf{Houston345}}\textbf{=0}$$

Where:

$$\text{RTRSVPOR} = \sum_{y} (\text{RNWF}_{y} * \text{RTORPA}_{y})$$

$$\text{RTRDP} = \sum_{y} (\text{RNWF}_{y} * \text{RTORDPA}_{y})$$

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

$$\text{RTHBP}_{hb,\ Houston345,\ y} = \sum_{b} (\text{HBDF}_{b,\ hb,\ Houston345} * \text{RTLMP}_{b,\ hb,\ Houston345,\ y})$$

$$\text{HUBDF}_{hb,\ Houston345} = \text{IF}(\text{HB}_{Houston345}=0,\ 0,\ 1 / \text{HB}_{Houston345})$$

$$\text{HBDF}_{b,\ hb,\ Houston345} = \text{IF}(\text{B}_{hb,\ Houston345}=0,\ 0,\ 1 / \text{B}_{hb,\ Houston345})$$

The above variables are defined as follows:

Variable	Unit	Description
$\text{RTSPP}_{\textit{Houston345}}$	\$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Hub, for the 15-minute Settlement Interval.
$\text{RTHBP}_{\textit{hb, Houston345, y}}$	\$/MWh	*Real-Time Hub Bus Price at Hub Bus per SCED interval*—The Real-Time energy price at Hub Bus *hb* for the SCED interval *y*.
RTRSVPOR	\$/MWh	*Real-Time Reserve Price for On-Line Reserves*—The Real-Time Reserve Price for On-Line Reserves for the 15-minute Settlement Interval.
RTORPA_{y}	\$/MWh	*Real-Time On-Line Reserve Price Adder per interval*—The Real-Time On-Line Reserve Price Adder for the SCED interval *y*.
RTRDP	\$/MWh	*Real-Time On-Line Reliability Deployment Price*—The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that are calculated from the Real-Time On-Line Reliability Deployment Price Adder.
RTORDPA_{y}	\$/MWh	*Real-Time On-Line Reliability Deployment Price Adder*—The Real-Time price adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
RNWF_{y}	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval.
$\text{RTLMP}_{\textit{b, hb, Houston345, y}}$	\$/MWh	*Real-Time Locational Marginal Price at Electrical Bus of Hub Bus per interval*—The Real-Time LMP at Electrical Bus *b* that is a component of Hub Bus *hb*, for the SCED interval *y*.

Variable	Unit	Description
$TLMP_{y}$	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the 15-minute Settlement Interval
$HUBDF_{hb, Houston345}$	none	*Hub Distribution Factor per Hub Bus*—The distribution factor of Hub Bus *hb*.
$HBDF_{b, hb, Houston345}$	none	*Hub Bus Distribution Factor per Electrical Bus of Hub Bus*—The distribution factor of Electrical Bus *b* that is a component of Hub Bus *hb*.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.
b	none	An energized Electrical Bus that is a component of a Hub Bus.
$B_{hb, Houston345}$	none	The total number of energized Electrical Buses in Hub Bus *hb*.
hb	none	A Hub Bus that is a component of the Hub.
$HB_{Houston345}$	none	The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus.

[NPRR1007 and NPRR1057: Replace applicable portions of paragraph (4) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1057:]

(4) The Real-Time Settlement Point Price of the Hub for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTSPP}_{\mathit{Houston345}} = \mathbf{Max\ [-\$251,\ (RTRDP\ +\ \sum_{y}\ (HUBLMP}_{\mathit{Houston345,\ y}} \mathbf{\ *\ RNWF}_{\mathit{y}} \mathbf{))]}$$

Where:

$$RTRDP = \sum_{y} (RNWF_{y} * RTRDPA_{y})$$

$$RNWF_{y} = TLMP_{y} / \sum_{y} TLMP_{y}$$

The above variables are defined as follows:

Variable	Unit	Description
$RTSPP_{Houston345}$	\$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Hub, for the 15-minute Settlement Interval.
RTRDP	\$/MWh	*Real-Time Reliability Deployment Price for Energy* —The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that are calculated from the Real-Time Reliability Deployment Price Adder for Energy.
$RTRDPA_{y}$	\$/MWh	*Real-Time Reliability Deployment Price Adder for Energy* —The Real-Time Price Adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
$HUBLMP_{Houston345, y}$	\$/MWh	*Hub Locational Marginal Price*—The Hub LMP for the Hub for the SCED Interval *y*.

RNWF $_{y}$	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval.
TLMP $_{y}$	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the 15-minute Settlement Interval
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.

3.5.2.4 West 345 kV Hub (West 345)

(1) The West 345 kV Hub is composed of the following listed Hub Buses:

	ERCOT Operations		
No.	Hub Bus	kV	Hub
1	MULBERRY	345	WEST
2	BOMSW	345	WEST
3	OECCS	345	WEST
4	BITTCR	345	WEST
5	FSHSW	345	WEST
6	FLCNS	345	WEST
7	GRSES	345	WEST
8	JCKSW	345	WEST
9	MDLNE	345	WEST
10	MOSSW	345	WEST
11	MGSES	345	WEST
12	DCTM	345	WEST
13	ODEHV	345	WEST
14	OKLA	345	WEST
15	REDCREEK	345	WEST
16	SWESW	345	WEST
17	TWINBU	345	WEST

(2) The West 345 kV Hub Price uses the aggregated Shift Factors of the Hub Buses for each hour of the Settlement Interval of the DAM in the Day-Ahead and is the simple average of the time weighted Hub Bus prices for each 15-minute Settlement Interval in Real-Time, for each Hub Bus included in this Hub.

(3) The Day-Ahead Settlement Point Price of the Hub for a given Operating Hour is calculated as follows:

$$\textbf{DASPP}_{\textit{West345}} = \textbf{DASL} - \sum_{c}(\textbf{DAHUBSF}_{\textit{West345, c}} * \textbf{DASP}_{c}), \text{ if } \textbf{HBBC}_{\textit{West345}} \neq 0$$

$$\textbf{DASPP}_{\textit{West345}} = \textbf{DASPP}_{\textit{ERCOT345Bus}}, \text{ if } \textbf{HBBC}_{\textit{West345}} = 0$$

Where:

$$\text{DAHUBSF}_{\,West345,\,c} = \sum_{hb} (\text{HUBDF}_{\,hb,\,West345,\,c} * \text{DAHBSF}_{\,hb,\,West345,\,c})$$

$$\text{DAHBSF}_{\,hb,\,West345,\,c} = \sum_{pb} (\text{HBDF}_{\,pb,\,hb,\,West345,\,c} * \text{DASF}_{\,pb,\,hb,\,West345,\,c})$$

$$\text{HUBDF}_{\,hb,\,West345,\,c} = \text{IF}(\text{HB}_{\,West345,\,c}{=}0,\ 0,\ 1 / \text{HB}_{\,West345,\,c})$$

$$\text{HBDF}_{\,pb,\,hb,\,West345,\,c} = \text{IF}(\text{PB}_{\,hb,\,West345,\,c}{=}0,\ 0,\ 1 / \text{PB}_{\,hb,\,West345,\,c})$$

The above variables are defined as follows:

Variable	Unit	Definition
DASPP $_{West345}$	\$/MWh	*Day-Ahead Settlement Point Price*—The DAM Settlement Point Price at the Hub, for the hour.
DASL	\$/MWh	*Day-Ahead System Lambda*—The DAM Shadow Price for the system power balance constraint for the hour.
DASP $_{c}$	\$/MWh	*Day-Ahead Shadow Price for a binding transmission constraint*—The DAM Shadow Price for the constraint *c* for the hour.
DAHUBSF $_{West345,c}$	none	*Day-Ahead Shift Factor of the Hub* —The DAM aggregated Shift Factor of a Hub for the constraint *c* for the hour.
DAHBSF $_{hb,West345,c}$	none	*Day-Ahead Shift Factor of the Hub Bus*—The DAM aggregated Shift Factor of a Hub Bus *hb* for the constraint *c* for the hour.
DASF $_{pb,hb,West345,c}$	none	*Day-Ahead Shift Factor of the power flow bus*—The DAM Shift Factor of a power flow bus *pb* that is a component of Hub Bus *hb* for the constraint *c* for the hour.
HUBDF $_{hb,\ West345,c}$	none	*Hub Distribution Factor per Hub Bus in a constraint*—The distribution factor of Hub Bus *hb* for the constraint *c* for the hour.
HBDF $_{pb,\ hb,\ West345,c}$	none	*Hub Bus Distribution Factor per power flow bus of Hub Bus in a constraint*—The distribution factor of power flow bus *pb* that is a component of Hub Bus *hb* for the constraint *c* for the hour.
pb	none	An energized power flow bus that is a component of a Hub Bus for the constraint *c*.
PB $_{hb,\ West345,c}$	none	The total number of energized power flow buses in Hub Bus *hb* for the constraint *c*.
hb	none	A Hub Bus that is a component of the Hub with at least one energized power flow bus for the constraint *c*.
HBBC $_{West345}$	none	The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus in base case.
HB $_{West345,c}$	none	The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus for the constraint *c*.
c	none	A DAM binding transmission constraint for the hour caused by either base case or a contingency.

(4) The Real-Time Settlement Point Price of the Hub for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTSPP}_{\mathit{West345}} = \mathbf{Max\ [-\$251, (RTRSVPOR + RTRDP +}$$

$$\sum_{hb} \mathbf{(HUBDF}_{\mathit{hb, West345}} \mathbf{* (} \sum_{y} \mathbf{(RTHBP}_{\mathit{hb, West345, y}} \mathbf{* TLMP}_{y}\mathbf{) /}$$
$$\mathbf{(} \sum_{y} \mathbf{TLMP}_{y}\mathbf{))))], if\ HB}_{\mathit{West345}} \mathbf{\neq 0}$$

$$\mathbf{RTSPP}_{\mathit{West345}} = \mathbf{RTSPP}_{\mathit{ERCOT345Bus}}\mathbf{, if\ HB}_{\mathit{West345}}\mathbf{=0}$$

Where:

$$RTRSVPOR = \sum_{y} (RNWF_{y} * RTORPA_{y})$$

$$RTRDP = \sum_{y} (RNWF_{y} * RTORDPA_{y})$$

$$RNWF_{y} = TLMP_{y} / \sum_{y} TLMP_{y}$$

$$RTHBP_{hb, West345, y} = \sum_{b} (HBDF_{b, hb, West345} * RTLMP_{b, hb, West345, y})$$

$$HUBDF_{hb, West345} = IF(HB_{West345}=0, 0, 1 / HB_{West345})$$

$$HBDF_{b, hb, West345} = IF(B_{hb, West345}=0, 0, 1 / B_{hb, West345})$$

The above variables are defined as follows:

Variable	Unit	Description
$RTSPP_{West345}$	\$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Hub, for the 15-minute Settlement Interval.
RTRSVPOR	\$/MWh	*Real-Time Reserve Price for On-Line Reserves*—The Real-Time Reserve Price for On-Line Reserves for the 15-minute Settlement Interval.
$RTORPA_{y}$	\$/MWh	*Real-Time On-Line Reserve Price Adder per interval*—The Real-Time On-Line Reserve Price Adder for the SCED interval *y*.
RTRDP	\$/MWh	*Real-Time On-Line Reliability Deployment Price*—The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that are calculated from the Real-Time On-Line Reliability Deployment Price Adder.
$RTORDPA_{y}$	\$/MWh	*Real-Time On-Line Reliability Deployment Price Adder*—The Real-Time price adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
$RNWF_{y}$	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval.
$RTHBP_{hb, West345, y}$	\$/MWh	*Real-Time Hub Bus Price at Hub Bus per SCED interval*—The Real-Time energy price at Hub Bus *hb* for the SCED interval *y*.

Variable	Unit	Description
$RTLMP_{b, hb, West345, y}$	$/MWh	*Real-Time Locational Marginal Price at Electrical Bus of Hub Bus per interval*—The Real-Time LMP at Electrical Bus *b* that is a component of Hub Bus *hb*, for the SCED interval *y*.
$TLMP_{y}$	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the 15-minute Settlement Interval.
$HUBDF_{hb, West345}$	none	*Hub Distribution Factor per Hub Bus*—The distribution factor of Hub Bus *hb*.
$HBDF_{b, hb, West345}$	none	*Hub Bus Distribution Factor per Electrical Bus of Hub Bus*—The distribution factor of Electrical Bus *b* that is a component of Hub Bus *hb*.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.
b	none	An energized Electrical Bus that is a component of a Hub Bus.
$B_{hb, West345}$	none	The total number of energized Electrical Buses in Hub Bus *hb*.
hb	none	A Hub Bus that is a component of the Hub.
$HB_{West345}$	none	The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus.

[NPRR1007 and NPRR1057: Replace applicable portions of paragraph (4) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation of NPRR1057:]

(4) The Real-Time Settlement Point Price of the Hub for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTSPP}_{West345} = \mathbf{Max\ [-\$251, (RTRDP + \sum_{y} (HUBLMP}_{West345,\ y}\ \mathbf{*\ RNWF}_{y}\mathbf{))]}$$

Where:

$$RTRDP = \sum_{y} (RNWF_{y} * RTRDPA_{y})$$

$$RNWF_{y} = TLMP_{y} / \sum_{y} TLMP_{y}$$

The above variables are defined as follows:

Variable	Unit	Description
$RTSPP_{West345}$	$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Hub, for the 15-minute Settlement Interval.
RTRDP	$/MWh	*Real-Time Reliability Deployment Price for Energy*—The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that are calculated from the Real-Time Reliability Deployment Price Adder for Energy.
$RTRDPA_{y}$	$/MWh	*Real-Time Reliability Deployment Price Adder for Energy*—The Real-Time Price Adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.

HUBLMP $_{West345,\,y}$	\$/MWh	*Hub Locational Marginal Price*—The Hub LMP for the Hub for the SCED Interval *y*.
RNWF $_{y}$	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval.
TLMP $_{y}$	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the 15-minute Settlement Interval.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.

3.5.2.5 Panhandle 345 kV Hub (Pan 345)

(1) The Panhandle 345 kV Hub is composed of the following listed Hub Buses:

	ERCOT Operations		
No.	Hub Bus	kV	Hub
1	ABERNATH	345	PAN
2	AJ_SWOPE	345	PAN
3	ALIBATES	345	PAN
4	CTT_CROS	345	PAN
5	CTT_GRAY	345	PAN
6	OGALLALA	345	PAN
7	RAILHEAD	345	PAN
8	TESLA	345	PAN
9	TULECNYN	345	PAN
10	W_CW_345	345	PAN
11	WHIT_RVR	345	PAN
12	WINDMILL	345	PAN

(2) The Panhandle 345 kV Hub Price uses the aggregated Shift Factors of the Hub Buses for each hour of the Settlement Interval of the DAM in the Day-Ahead and is the simple average of the time weighted Hub Bus prices for each 15-minute Settlement Interval in Real-Time, for each Hub Bus included in this Hub.

(3) The Day-Ahead Settlement Point Price of the Hub for a given Operating Hour is calculated as follows:

$$\textbf{DASPP}_{\,Pan345} = \textbf{DASL} - \sum_{c}(\textbf{DAHUBSF}_{\,Pan345,\,c} * \textbf{DASP}_{\,c}),\ \textbf{if HBBC}_{\,Pan345} \neq 0$$

$$\textbf{DASPP}_{\,Pan345} = \textbf{DASPP}_{\,ERCOT345Bus},\ \textbf{if HBBC}_{\,Pan345} = 0$$

Where:

$$\text{DAHUBSF}_{\,Pan345,\,c} = \sum_{hb}(\text{HUBDF}_{\,hb,\,Pan345,\,c} * \text{DAHBSF}_{\,hb,\,Pan345,\,c})$$

$$\text{DAHBSF}_{\,hb,\,Pan345,\,c} = \sum_{pb} (\text{HBDF}_{\,pb,\,hb,\,Pan345,\,c} * \text{DASF}_{\,pb,\,hb,\,Pan345,\,c})$$

$$\text{HUBDF}_{\,hb,\,Pan345,\,c} = \text{IF}(\text{HB}_{\,Pan345,\,c}=0,\,0,\,1 \,/\, \text{HB}_{\,Pan345,\,c})$$

$$\text{HBDF}_{\,pb,\,hb,\,Pan345,\,c} = \text{IF}(\text{PB}_{\,hb,\,Pan345,\,c}=0,\,0,\,1 \,/\, \text{PB}_{\,hb,\,Pan345,\,c})$$

The above variables are defined as follows:

Variable	Unit	Definition
$\text{DASPP}_{\,Pan345}$	$/MWh	*Day-Ahead Settlement Point Price*—The DAM Settlement Point Price at the Hub, for the hour.
DASL	$/MWh	*Day-Ahead System Lambda*—The DAM Shadow Price for the system power balance constraint for the hour.
$\text{DASP}_{\,c}$	$/MWh	*Day-Ahead Shadow Price for a binding transmission constraint*—The DAM Shadow Price for the constraint *c* for the hour.
$\text{DAHUBSF}_{\,Pan345,c}$	none	*Day-Ahead Shift Factor of the Hub* —The DAM aggregated Shift Factor of a Hub for the constraint *c* for the hour.
$\text{DAHBSF}_{\,hb,Pan345,c}$	none	*Day-Ahead Shift Factor of the Hub Bus*—The DAM aggregated Shift Factor of a Hub Bus *hb* for the constraint *c* for the hour.
$\text{DASF}_{\,pb,hb,Pan345,c}$	none	*Day-Ahead Shift Factor of the power flow bus*—The DAM Shift Factor of a power flow bus *pb* that is a component of Hub Bus *hb* for the constraint *c* for the hour.
$\text{HUBDF}_{\,hb,\,Pan345,c}$	none	*Hub Distribution Factor per Hub Bus in a constraint*—The distribution factor of Hub Bus *hb* for the constraint *c* for the hour.
$\text{HBDF}_{\,pb,\,hb,\,Pan345,c}$	none	*Hub Bus Distribution Factor per power flow bus of Hub Bus in a constraint*—The distribution factor of power flow bus *pb* that is a component of Hub Bus *hb* for the constraint *c* for the hour.
pb	none	An energized power flow bus that is a component of a Hub Bus for the constraint *c*.
$\text{PB}_{\,hb,\,Pan345,c}$	none	The total number of energized power flow buses in Hub Bus *hb* for the constraint *c*.
hb	none	A Hub Bus that is a component of the Hub with at least one energized power flow bus for the constraint *c*.
$\text{HBBC}_{\,Pan345}$	none	The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus in base case.
$\text{HB}_{\,Pan345,c}$	none	The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus for the constraint *c*.
c	none	A DAM binding transmission constraint for the hour caused by either base case or a contingency.

(4) The Real-Time Settlement Point Price of the Hub for a given 15-minute Settlement Interval is calculated as follows:

$\text{RTSPP}_{\,Pan345}$ = Max [-$251, (RTRSVPOR + RTRDP +

$$\sum_{hb} (\textbf{HUBDF}_{\,hb,\,Pan345} * (\sum_{y} (\textbf{RTHBP}_{\,hb,\,Pan345,\,y} * \textbf{TLMP}_{\,y}) / (\sum_{y} \textbf{TLMP}_{\,y}))))], \textbf{ if HB}_{Pan345} \neq 0$$

$$\textbf{RTSPP}_{\,Pan345} = \textbf{RTSPP}_{\,ERCOT345Bus}, \textbf{ if HB}_{Pan345} = 0$$

Where:

$$\text{RTRSVPOR} = \sum_{y} (\text{RNWF}_{\,y} * \text{RTORPA}_{\,y})$$

$$\text{RTRDP} = \sum_{y} (\text{RNWF}_{\,y} * \text{RTORDPA}_{\,y})$$

$$\text{RNWF}_{\,y} = \text{TLMP}_{\,y} / \sum_{y} \text{TLMP}_{\,y}$$

$$\text{RTHBP}_{\,hb,\,Pan345,\,y} = \sum_{b} (\text{HBDF}_{\,b,\,hb,\,Pan345} * \text{RTLMP}_{\,b,\,hb,\,Pan345,\,y})$$

$$\text{HUBDF}_{\,hb,\,Pan345} = \text{IF}(\text{HB}_{\,Pan345}=0,\ 0,\ 1 / \text{HB}_{\,Pan345})$$

$$\text{HBDF}_{\,b,\,hb,\,Pan345} = \text{IF}(\text{B}_{\,hb,\,Pan345}=0,\ 0,\ 1 / \text{B}_{\,hb,\,Pan345})$$

The above variables are defined as follows:

Variable	Unit	Description
$\text{RTSPP}_{\,Pan345}$	\$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Hub for the 15-minute Settlement Interval.
RTRSVPOR	\$/MWh	*Real-Time Reserve Price for On-Line Reserves*—The Real-Time Reserve Price for On-Line Reserves for the 15-minute Settlement Interval.
$\text{RTORPA}_{\,y}$	\$/MWh	*Real-Time On-Line Reserve Price Adder per interval*—The Real-Time On-Line Reserve Price Adder for the SCED interval *y*.
RTRDP	\$/MWh	*Real-Time On-Line Reliability Deployment Price*—The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that are calculated from the Real-Time On-Line Reliability Deployment Price Adder.
$\text{RTORDPA}_{\,y}$	\$/MWh	*Real-Time On-Line Reliability Deployment Price Adder*—The Real-Time price adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
$\text{RNWF}_{\,y}$	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval.
$\text{RTHBP}_{\,hb,\,Pan345,\,y}$	\$/MWh	*Real-Time Hub Bus Price at Hub Bus per SCED interval*—The Real-Time energy price at Hub Bus *hb* for the SCED interval *y*.
$\text{RTLMP}_{\,b,\,hb,\,Pan345,\,y}$	\$/MWh	*Real-Time Locational Marginal Price at Electrical Bus of Hub Bus per interval*—The Real-Time LMP at Electrical Bus *b* that is a component of Hub Bus *hb* for the SCED interval *y*.
$\text{TLMP}_{\,y}$	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the 15-minute Settlement Interval.

Variable	Unit	Description
$HUBDF_{hb,\ Pan345}$	none	*Hub Distribution Factor per Hub Bus*—The distribution factor of Hub Bus *hb*.
$HBDF_{b,\ hb,\ Pan345}$	none	*Hub Bus Distribution Factor per Electrical Bus of Hub Bus*—The distribution factor of Electrical Bus *b* that is a component of Hub Bus *hb*.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.
b	none	An energized Electrical Bus that is a component of a Hub Bus.
$B_{hb,\ Pan345}$	none	The total number of energized Electrical Buses in Hub Bus *hb*.
hb	none	A Hub Bus that is a component of the Hub.
HB_{Pan345}	none	The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus.

[NPRR1007 and NPRR1057: Replace applicable portions of paragraph (4) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1057:]

(4) The Real-Time Settlement Point Price of the Hub for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTSPP}_{Pan345} = \mathbf{Max\ [-\$251,\ (RTRDP +}\ \sum_{y} \mathbf{(HUBLMP}_{Pan345,\ y}\ \mathbf{*\ RNWF}_{y}\ \mathbf{))]}$$

Where:

$$RTRDP = \sum_{y} (RNWF_{y} * RTRDPA_{y})$$

$$RNWF_{y} = TLMP_{y} / \sum_{y} TLMP_{y}$$

The above variables are defined as follows:

Variable	Unit	Description
$RTSPP_{Pan345}$	\$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Hub for the 15-minute Settlement Interval.
RTRDP	\$/MWh	*Real-Time Reliability Deployment Price for Energy*—The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that are calculated from the Real-Time Reliability Deployment Price Adder for Energy.
$RTRDPA_{y}$	\$/MWh	*Real-Time Reliability Deployment Price Adder for Energy*—The Real-Time Price Adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
$HUBLMP_{Pan345,\ y}$	\$/MWh	*Hub Locational Marginal Price*—The Hub LMP for the Hub for the SCED Interval *y*.
$RNWF_{y}$	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval.

TLMP $_y$	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the 15-minute Settlement Interval.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.

[NPRR941, NPRR1007, and NPRR1057: Insert applicable portions of Section 3.5.2.6 below upon system implementation for NPRR941 or NPRR1057; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; and renumber accordingly:]

3.5.2.6 Lower Rio Grande Valley Hub (LRGV 138/345)

(1) The Lower Rio Grande Valley Hub 138/345 kV Hub is composed of the following listed Hub Buses:

No.	ERCOT Operations Hub Bus	kV	Hub
1	AIRPORT	138	LRGV
2	ALBERTA	138	LRGV
3	BATES	138	LRGV
4	FRONTERA	138	LRGV
5	GARZA	138	LRGV
6	HARLNSW	138	LRGV
7	HEC	138	LRGV
8	KEY_SW	138	LRGV
9	LA_PALMA_345	345	LRGV
10	LA_PALMA_138	138	LRGV
11	LASPULGA	138	LRGV
12	LISTON	138	LRGV
13	LOMA_ALT	138	LRGV
14	MARCONI	138	LRGV
15	MILHWY	138	LRGV
16	MILITARY	138	LRGV
17	MV_WEDN4	138	LRGV
18	N_MCALLN	138	LRGV
19	NEDIN_345	345	LRGV
20	NEDIN_138	138	LRGV
21	OLEANDER	138	LRGV
22	P_ISABEL	138	LRGV
23	PALMHRTP	138	LRGV
24	PALMITO_345	345	LRGV

25	PALMITO_138	138	LRGV
26	PAREDES	138	LRGV
27	PHARMVEC	138	LRGV
28	PHARR	138	LRGV
29	PRICE_RD	138	LRGV
30	RAILROAD	138	LRGV
31	RAYMND2	138	LRGV
32	REDTAP	138	LRGV
33	RIO_GRAN	138	LRGV
34	RIOHONDO_345	345	LRGV
35	RIOHONDO_138	138	LRGV
36	ROMA_SW	138	LRGV
37	S_MCALLN	138	LRGV
38	SCARBIDE	138	LRGV
39	SILASRAY	138	LRGV
40	STEWART	138	LRGV
41	WESLACO	138	LRGV

(2) The Lower Rio Grande Valley 138/345 kV Hub Price uses the aggregated Shift Factors of the Hub Buses for each hour of the Settlement Interval of the DAM in the Day-Ahead and is the simple average of the time weighted Hub Bus prices for each 15-minute Settlement Interval in Real-Time, for each Hub Bus included in this Hub.

(3) The Day-Ahead Settlement Point Price of the Hub for a given Operating Hour is calculated as follows:

$$\mathbf{DASPP}_{\ LRGV\ 138/345} = \mathbf{DASL} - \sum_{c} (\mathbf{DAHUBSF}_{\ LRGV\ 138/345,\ c} * \mathbf{DASP}_{\ c}),\ \textbf{if HBBC}_{\ LRGV138/345} \neq 0$$

$$\mathbf{DASPP}_{\ LRGV138/345} = \mathbf{DASPP}_{\ ERCOT345Bus},\ \textbf{if HBBC}_{\ LRGV138/345} = 0$$

Where:

$$\text{DAHUBSF}_{\ LRGV138/345,\ c} = \sum_{hb} (\text{HUBDF}_{\ hb,\ LRGV138/345,\ c} * \text{DAHBSF}_{\ hb,\ LRGV138/345,\ c})$$

$$\text{DAHBSF}_{\ hb,\ LRGV138/345,\ c} = \sum_{pb} (\text{HBDF}_{\ pb,\ hb,\ LRGV138/345,\ c} * \text{DASF}_{\ pb,\ hb,\ LRGV138/345,\ c})$$

$$\text{HUBDF}_{\ hb,\ LRGV138/345,\ c} = \text{IF}(\text{HB}_{\ LRGV138/345,\ c}=0,\ 0,\ 1 / \text{HB}_{\ LRGV138/345,\ c})$$

$$HBDF_{pb,\ hb,\ LRGV138/345,\ c} = IF(PB_{hb,\ LRGV138/345,\ c}=0,\ 0,\ 1\ /\ PB_{hb,\ LRGV138/345,\ c})$$

The above variables are defined as follows:

Variable	Unit	Definition
$DASPP_{LRGV138/345}$	\$/MWh	*Day-Ahead Settlement Point Price*—The DAM Settlement Point Price at the Hub, for the hour.
DASL	\$/MWh	*Day-Ahead System Lambda*—The DAM Shadow Price for the system power balance constraint for the hour.
$DASP_{c}$	\$/MWh	*Day-Ahead Shadow Price for a binding transmission constraint*—The DAM Shadow Price for the constraint *c* for the hour.
$DAHUBSF_{LRGV138/345,c}$	none	*Day-Ahead Shift Factor of the Hub* —The DAM aggregated Shift Factor of a Hub for the constraint *c* for the hour.
$DAHBSF_{hb,\ LRGV138/345,c}$	none	*Day-Ahead Shift Factor of the Hub Bus*—The DAM aggregated Shift Factor of a Hub Bus *hb* for the constraint *c* for the hour.
$DASF_{pb,hb,\ LRGV138/345,c}$	none	*Day-Ahead Shift Factor of the power flow bus*—The DAM Shift Factor of a power flow bus *pb* that is a component of Hub Bus *hb* for the constraint *c* for the hour.
$HUBDF_{hb,\ LRGV138/345,c}$	none	*Hub Distribution Factor per Hub Bus in a constraint*—The distribution factor of Hub Bus *hb* for the constraint *c* for the hour.
$HBDF_{pb,\ hb,\ LRGV138/345,c}$	none	*Hub Bus Distribution Factor per power flow bus of Hub Bus in a constraint*—The distribution factor of power flow bus *pb* that is a component of Hub Bus *hb* for the constraint *c* for the hour.
pb	none	An energized power flow bus that is a component of a Hub Bus for the constraint *c*.
$PB_{hb,\ LRGV138/345,c}$	none	The total number of energized power flow buses in Hub Bus *hb* for the constraint *c*.
hb	none	A Hub Bus that is a component of the Hub with at least one energized power flow bus for the constraint *c*.
$HBBC_{LRGV138/345}$	none	The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus in base case.
$HB_{LRGV138/345,c}$	none	The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus for the constraint *c*.
c	none	A DAM binding transmission constraint for the hour caused by either base case or a contingency.

(4) The Real-Time Settlement Point Price of the Hub for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTSPP}_{LRGV138/345} = \mathbf{Max\ [-\$251,\ (RTRDP + \sum_{y}(HUBLMP}_{LRGV138/345,\ y}\ \mathbf{*\ RNWF}_{y}\mathbf{))]}$$

Where:

$$RTRDP = \sum_{y}(RNWF_{y}\ *\ RTRDPA_{y})$$

$$\text{RNWF}_y = \text{TLMP}_y / \sum_y \text{TLMP}_y$$

The above variables are defined as follows:

Variable	Unit	Description
$\text{RTSPP}_{LRGV138/345kV}$	\$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Hub for the 15-minute Settlement Interval.
RTRDP	\$/MWh	*Real-Time Reliability Deployment Price for Energy*—The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that are calculated from the Real-Time Reliability Deployment Price Adder for Energy.
RTRDPA_y	\$/MWh	*Real-Time Reliability Deployment Price Adder for Energy*—The Real-Time Price Adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
$\text{HUBLMP}_{LRGV138/345,\ y}$	\$/MWh	*Hub Locational Marginal Price*—The Hub LMP for the Hub for the SCED Interval *y*.
RNWF_y	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval.
TLMP_y	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the 15-minute Settlement Interval.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.

3.5.2.6 ERCOT Hub Average 345 kV Hub (ERCOT 345)

(1) The ERCOT Hub Average 345 kV Hub price for Day-Ahead is calculated for each hour using the aggregated Shift Factors of four Hubs: the North 345 kV Hub, the South 345 kV Hub, the Houston 345 kV Hub, and the West 345 kV Hub. The ERCOT Hub Average 345 kV Hub price for Real-Time is the simple average of four prices from the applicable time period: the North 345 kV Hub price, the South 345 kV Hub price, the Houston 345 kV Hub price, and the West 345 kV Hub price. The Panhandle 345 kV Hub is not included in either the Day-Ahead or Real-Time ERCOT Hub Average 345 kV Hub price.

[NPRR941: Replace paragraph (1) above upon system implementation:]

(1) The ERCOT Hub Average 345 kV Hub price for Day-Ahead is calculated for each hour using the aggregated Shift Factors of four Hubs: the North 345 kV Hub, the South 345 kV Hub, the Houston 345 kV Hub, and the West 345 kV Hub. The ERCOT Hub Average 345 kV Hub price for Real-Time is the simple average of four prices from the applicable time period: the North 345 kV Hub price, the South 345 kV Hub price, the Houston 345 kV Hub price, and the West 345 kV Hub price. The Panhandle 345 kV

Hub and the Lower Rio Grande Valley 138/345 kV Hub are not included in either the Day-Ahead or Real-Time ERCOT Hub Average 345 kV Hub price.

(2) The Day-Ahead Settlement Point Price for the Hub "ERCOT 345" for a given Operating Hour is calculated as follows:

$$\mathbf{DASPP}_{\mathit{ERCOT345}} = \mathbf{DASL} - \sum_{c} (\mathbf{DAHUBSF}_{\mathit{ERCOT345,\,c}} * \mathbf{DASP}_{\mathit{c}}), \text{ if } \mathbf{HBBC}_{\mathit{ERCOT345Bus}} \neq 0$$

$$\mathbf{DASPP}_{\mathit{ERCOT345}} = \mathbf{DASPP}_{\mathit{ERCOT345Bus}}, \text{ if } \mathbf{HBBC}_{\mathit{ERCOT345Bus}} = 0$$

Where:

$$\text{DAHUBSF}_{\mathit{ERCOT345,\,c}} = (\text{DAHUBSF}_{\mathit{North345,\,c}} + \text{DAHUBSF}_{\mathit{South345,\,c}} + \text{DAHUBSF}_{\mathit{Houston345,\,c}} + \text{DAHUBSF}_{\mathit{West345,\,c}}) / 4$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
$\text{DASPP}_{\mathit{ERCOT345}}$	\$/MWh	*Day-Ahead Settlement Point Price at ERCOT 345*—The DAM Settlement Point Price at ERCOT 345 Hub for the hour.
DASL	\$/MWh	*Day-Ahead System Lambda*—The DAM Shadow Price for the system power balance constraint for the hour.
DASP_{c}	\$/MWh	*Day-Ahead Shadow Price for a binding transmission constraint*—The DAM Shadow Price for the constraint *c* for the hour.
$\text{DAHUBSF}_{\mathit{ERCOT345,c}}$	none	*Day-Ahead Shift Factor of ERCOT 345* —The DAM aggregated Shift Factor of ERCOT 345 Hub for the constraint *c* for the hour.
$\text{DAHUBSF}_{\mathit{North345,c}}$	none	*Day-Ahead Shift Factor of North 345*—The DAM aggregated Shift Factor of the North 345 Hub for the constraint *c* for the hour.
$\text{DAHUBSF}_{\mathit{South345,c}}$	none	*Day-Ahead Shift Factor of South 345*—The DAM aggregated Shift Factor of the South 345 Hub for the constraint *c* for the hour.
$\text{DAHUBSF}_{\mathit{Houston345,c}}$	none	*Day-Ahead Shift Factor of Houston 345*—The DAM aggregated Shift Factor of the Houston 345 Hub for the constraint *c* for the hour.
$\text{DAHUBSF}_{\mathit{West345,c}}$	none	*Day-Ahead Shift Factor of West 345*—The DAM aggregated Shift Factor of the West 345 Hub for the constraint *c* for the hour.
$\text{HBBC}_{\mathit{ERCOT345Bus}}$	none	The total number of Hub Buses in the ERCOT Bus Average 345 kV Hub (ERCOT 345 Bus) with at least one energized component in each Hub Bus in base case. The Hub "ERCOT 345 Bus" includes any Hub Bus defined in the Hub "North 345", "South 345", "Houston 345" and "West 345".
c	none	A DAM binding transmission constraint for the hour caused by either base case or a contingency.

(3) The Real-Time Settlement Point Price for the Hub "ERCOT 345" for a given 15-minute Settlement Interval is calculated as follows:

$$\textbf{RTSPP}_{\,ERCOT345} = (\textbf{RTSPP}_{\,North345} + \textbf{RTSPP}_{\,South345} + \textbf{RTSPP}_{\,Houston345} + \textbf{RTSPP}_{\,West345}) \,/\, 4$$

The above variables are defined as follows:

Variable	Unit	Definition
$RTSPP_{\,ERCOT345}$	\$/MWh	*Real-Time Settlement Point Price at ERCOT 345*—The Real-Time Settlement Point Price at ERCOT 345 Hub for the 15-minute Settlement Interval.
$RTSPP_{\,North345}$	\$/MWh	*Real-Time Settlement Point Price at North 345*—The Real-Time Settlement Point Price at the North 345 Hub for the 15-minute Settlement Interval.
$RTSPP_{\,South345}$	\$/MWh	*Real-Time Settlement Point Price at South 345*—The Real-Time Settlement Point Price at the South 345 Hub for the 15-minute Settlement Interval.
$RTSPP_{\,Houston345}$	\$/MWh	*Real-Time Settlement Point Price at Houston 345*—The Real-Time Settlement Point Price at the Houston 345 Hub for the 15-minute Settlement Interval.
$RTSPP_{\,West345}$	\$/MWh	*Real-Time Settlement Point Price at West 345*—The Real-Time Settlement Point Price at the West 345 Hub for the 15-minute Settlement Interval.

3.5.2.7 ERCOT Bus Average 345 kV Hub (ERCOT 345 Bus)

(1) The ERCOT Bus Average 345 kV Hub is composed of the Hub Buses listed in Section 3.5.2.1, North 345 kV Hub (North 345); Section 3.5.2.2, South 345 kV Hub (South 345); Section 3.5.2.3, Houston 345 kV Hub (Houston 345); and Section 3.5.2.4, West 345 kV Hub (West 345). The Panhandle 345 kV Hub is not included in the ERCOT Bus Average 345 kV Hub price.

[NPRR941: Replace paragraph (1) above upon system implementation:]

(1) The ERCOT Bus Average 345 kV Hub is composed of the Hub Buses listed in Section 3.5.2.1, North 345 kV Hub (North 345); Section 3.5.2.2, South 345 kV Hub (South 345); Section 3.5.2.3, Houston 345 kV Hub (Houston 345); and Section 3.5.2.4, West 345 kV Hub (West 345). The Panhandle 345 kV Hub and the Lower Rio Grande Valley 138/345 kV Hub are not included in the ERCOT Bus Average 345 kV Hub price.

(2) The ERCOT Bus Average 345 kV Hub uses the aggregated Shift Factors of the Hub Buses for each hour of the Settlement Interval of the DAM in the Day-Ahead and is the simple average of the time weighted Hub Bus prices for each 15-minute Settlement Interval in Real-Time, for each Hub Bus included in this Hub.

(3) The Day-Ahead Settlement Point Price of the Hub for a given Operating Hour is calculated as follows:

$$\textbf{DASPP}_{\,ERCOT345Bus} = \textbf{DASL} - \sum_{c} (\textbf{DAHUBSF}_{\,ERCOT345Bus,\,c} * \textbf{DASP}_{\,c}), \text{ if } \textbf{HBBC}_{\,ERCOT345Bus} \neq 0$$

$$\textbf{DASPP}_{\,ERCOT345Bus} = 0, \text{ if } \textbf{HBBC}_{\,ERCOT345Bus} = 0$$

Where:

$$DAHUBSF_{ERCOT345Bus,\ c} = \sum_{hb} (HUBDF_{hb,\ ERCOT345Bus,\ c} * DAHBSF_{hb,\ ERCOT345Bus,\ c})$$

$$DAHBSF_{hb,\ ERCOT345Bus,\ c} = \sum_{pb} (HBDF_{pb,\ hb,\ ERCOT345Bus,\ c} * DASF_{pb,\ hb,\ ERCOT345Bus,\ c})$$

$$HUBDF_{hb,\ ERCOT345Bus,\ c} = IF(HB_{ERCOT345Bus,\ c}=0,\ 0,\ 1\ /\ HB_{ERCOT345Bus,\ c})$$

$$HBDF_{pb,\ hb,\ ERCOT345Bus,\ c} = IF(PB_{hb,\ ERCOT345Bus,\ c}=0,\ 0,\ 1\ /\ PB_{hb,\ ERCOT345Bus,\ c})$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
$DASPP_{ERCOT345Bus}$	\$/MWh	*Day-Ahead Settlement Point Price*—The DAM Settlement Point Price at the Hub, for the hour.
DASL	\$/MWh	*Day-Ahead System Lambda*—The DAM Shadow Price for the system power balance constraint for the hour.
$DASP_{c}$	\$/MWh	*Day-Ahead Shadow Price for a binding transmission constraint*—The DAM Shadow Price for the constraint *c* for the hour.
$DAHUBSF_{ERCOT345Bus,c}$	none	*Day-Ahead Shift Factor of the Hub* —The DAM aggregated Shift Factor of a Hub for the constraint *c* for the hour.
$DAHBSF_{hb,ERCOT345Bus,c}$	none	*Day-Ahead Shift Factor of the Hub Bus*—The DAM aggregated Shift Factor of a Hub Bus *hb* for the constraint *c* for the hour.
$DASF_{pb,hb,ERCOT345Bus,c}$	none	*Day-Ahead Shift Factor of the power flow bus*—The DAM Shift Factor of a power flow bus *pb* that is a component of Hub Bus *hb* for the constraint *c* for the hour.
$HUBDF_{hb,ERCOT345Bus,c}$	none	*Hub Distribution Factor per Hub Bus in a constraint*—The distribution factor of Hub Bus *hb* for the constraint *c* for the hour.
$HBDF_{pb,\ hb,\ ERCOT345Bus,c}$	none	*Hub Bus Distribution Factor per power flow bus of Hub Bus in a constraint*—The distribution factor of power flow bus *pb* that is a component of Hub Bus *hb* for the constraint *c* for the hour.
pb	none	An energized power flow bus that is a component of a Hub Bus for the constraint *c*.
$PB_{hb,\ ERCOT345Bus,c}$	none	The total number of energized power flow buses in Hub Bus *hb* for the constraint *c*.
hb	none	A Hub Bus that is a component of the ERCOT Bus Average 345 kV Hub (ERCOT 345 Bus) with at least one energized power flow bus for the constraint *c*. The Hub "ERCOT 345 Bus" includes any Hub Bus defined in the Hub "North 345", "South 345", "Houston 345" and "West 345".
$HBBC_{ERCOT345Bus}$	none	The total number of Hub Buses in the ERCOT Bus Average 345 kV Hub (ERCOT 345 Bus) with at least one energized component in each Hub Bus in base case. The Hub "ERCOT 345 Bus" includes any Hub Bus defined in the Hub "North 345", "South 345", "Houston 345" and "West 345".
$HB_{ERCOT345Bus,c}$	none	The total number of Hub Buses in the ERCOT Bus Average 345 kV Hub (ERCOT 345 Bus) with at least one energized component in each Hub Bus for the constraint *c*. The Hub "ERCOT 345 Bus" includes any Hub Bus

Variable	Unit	Definition
		defined in the Hub "North 345", "South 345", "Houston 345" and "West 345".
c	none	A DAM binding transmission constraint for the hour caused by either base case or a contingency.

(4) The Real-Time Settlement Point Price of the Hub for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTSPP}_{\mathit{ERCOT345Bus}} = \mathbf{Max\ [-\$251, (RTRSVPOR + RTRDP +} \sum_{hb} \mathbf{(HUBDF}_{\mathit{hb, ERCOT345Bus}} \mathbf{* (}\sum_{y} \mathbf{(RTHBP}_{\mathit{hb, ERCOT345Bus, y}} \mathbf{* TLMP}_{y}\mathbf{) / (}\sum_{y} \mathbf{TLMP}_{y}\mathbf{))))], if\ HB}_{\mathit{ERCOT345Bus}} \neq \mathbf{0}$$

$$\mathbf{RTSPP}_{\mathbf{ERCOT345Bus}} = \mathbf{0, if\ HB}_{\mathbf{ERCOT345Bus}} = \mathbf{0}$$

Where:

$$\text{RTRSVPOR} = \sum_{y} (\text{RNWF}_{y} * \text{RTORPA}_{y})$$

$$\text{RTRDP} = \sum_{y} (\text{RNWF}_{y} * \text{RTORDPA}_{y})$$

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

$$\text{RTHBP}_{\mathit{hb, ERCOT345Bus, y}} = \sum_{b} (\text{HBDF}_{\mathit{b, hb, ERCOT345Bus}} * \text{RTLMP}_{\mathit{b, hb, ERCOT345Bus, y}})$$

$$\text{HUBDF}_{\mathit{hb, ERCOT345Bus}} = 1 / (\text{HB}_{\mathit{North345}} + \text{HB}_{\mathit{South345}} + \text{HB}_{\mathit{Houston345}} + \text{HB}_{\mathit{West345}})$$

If Electrical Bus *b* is a component of "North 345"

$$\text{HBDF}_{\mathit{b, hb, ERCOT345Bus}} = \text{IF}(\text{B}_{\mathit{hb, North345}}=0, 0, 1 / \text{B}_{\mathit{hb, North345}})$$

Otherwise

If Electrical Bus *b* is a component of "South 345"

$$\text{HBDF}_{\mathit{b, hb, ERCOT345Bus}} = \text{IF}(\text{B}_{\mathit{hb, South345}}=0, 0, 1 / \text{B}_{\mathit{hb, South345}})$$

Otherwise

If Electrical Bus *b* is a component of "Houston 345"

$$\text{HBDF}_{\mathit{b, hb, ERCOT345Bus}} = \text{IF}(\text{B}_{\mathit{hb, Houston345}}=0, 0, 1 / \text{B}_{\mathit{hb, Houston345}})$$

Otherwise

$$\text{HBDF}_{\mathit{b, hb, ERCOT345Bus}} = \text{IF}(\text{B}_{\mathit{hb, West345}}=0, 0, 1 / \text{B}_{\mathit{hb, West345}})$$

The above variables are defined as follows:

Variable	Unit	Description
$RTSPP_{ERCOT345Bus}$	$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Hub, for the 15-minute Settlement Interval.
RTRSVPOR	$/MWh	*Real-Time Reserve Price for On-Line Reserves*—The Real-Time Reserve Price for On-Line Reserves for the 15-minute Settlement Interval.
$RTORPA_{y}$	$/MWh	*Real-Time On-Line Reserve Price Adder per interval*—The Real-Time On-Line Reserve Price Adder for the SCED interval *y*.
RTRDP	$/MWh	*Real-Time On-Line Reliability Deployment Price*—The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that are calculated from the Real-Time On-Line Reliability Deployment Price Adder.
$RTORDPA_{y}$	$/MWh	*Real-Time On-Line Reliability Deployment Price Adder*—The Real-Time price adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
$RNWF_{y}$	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval.
$RTHBP_{hb, ERCOT345Bus, y}$	$/MWh	*Real-Time Hub Bus Price at Hub Bus per SCED interval*—The Real-Time energy price at Hub Bus *hb* for the SCED interval *y*.
$RTLMP_{b, hb, ERCOT345Bus, y}$	$/MWh	*Real-Time Locational Marginal Price at Electrical Bus of Hub Bus per interval*—The Real-Time LMP at Electrical Bus *b* that is a component of Hub Bus *hb*, for the SCED interval *y*.
$TLMP_{y}$	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the 15-minute Settlement Interval.
$HUBDF_{hb, ERCOT345Bus}$	none	*Hub Distribution Factor per Hub Bus*—The distribution factor of Hub Bus *hb*.
$HBDF_{b, hb, ERCOT345Bus}$	none	*Hub Bus Distribution Factor per Electrical Bus of Hub Bus*—The distribution factor of Electrical Bus *b* that is a component of Hub Bus *hb*.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.
b	none	An energized Electrical Bus that is a component of a Hub Bus.
$B_{hb, North345}$	none	The total number of energized Electrical Buses in Hub Bus *hb* that is a component of “North 345.”
$B_{hb, South345}$	none	The total number of energized Electrical Buses in Hub Bus *hb* that is a component of “South 345.”
$B_{hb, Houston345}$	none	The total number of energized Electrical Buses in Hub Bus *hb* that is a component of “Houston 345.”
$B_{hb, West345}$	none	The total number of energized Electrical Buses in Hub Bus *hb* that is a component of “West 345.”
hb	none	A Hub Bus that is a component of the Hub.
$HB_{North345}$	none	The total number of Hub Buses in “North 345.”
$HB_{South345}$	none	The total number of Hub Buses in “South 345.”
$HB_{Houston345}$	none	The total number of Hub Buses in “Houston 345.”
$HB_{West345}$	none	The total number of Hub Buses in “West 345.”

[NPRR1007 and NPRR1057: Replace applicable portions of paragraph (4) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1057:]

(4) The Real-Time Settlement Point Price of the Hub for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTSPP}_{\mathit{ERCOT345Bus}} = \mathbf{Max\ [-\$251, (RTRDP + \sum_{y} (HUBLMP}_{\mathbf{\mathit{ERCOT345Bus,y}}} \mathbf{* RNWF}_{\mathbf{\mathit{y}}}\mathbf{))]}$$

Where:

$$RTRDP = \sum_{y} (RNWF_{y} * RTRDPA_{y})$$

$$RNWF_{y} = TLMP_{y} / \sum_{y} TLMP_{y}$$

The above variables are defined as follows:

Variable	Unit	Description
$RTSPP_{ERCOT345Bus}$	$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Hub, for the 15-minute Settlement Interval.
RTRDP	$/MWh	*Real-Time Reliability Deployment Price for Energy*—The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that are calculated from the Real-Time Reliability Deployment Price Adder for Energy.
$RTRDPA_{y}$	$/MWh	*Real-Time Reliability Deployment Price Adder for Energy*—The Real-Time Price Adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
$HUBLMP_{ERCOT345Bus,y}$	$/MWh	*Hub Locational Marginal Price for the ERCOT345Bus*—The Hub LMP for the ERCOT Bus Average 345 kV Hub (ERCOT 345 Bus), for the SCED Interval *y*.
$RNWF_{y}$	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval.
$TLMP_{y}$	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the 15-minute Settlement Interval.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.

3.5.3 ERCOT Responsibilities for Managing Hubs

3.5.3.1 Posting of Hub Buses and Electrical Buses included in Hubs

(1) ERCOT shall post a list of all the Hub Buses included in each Hub on the ERCOT website. The list must include the name and kV rating for each Electrical Bus included in each Hub Bus.

3.5.3.2 Calculation of Hub Prices

(1) ERCOT shall calculate Hub prices for each Settlement Interval as identified in the description of each Hub.

3.6 Load Participation

3.6.1 Load Resource Participation

(1) A Load Resource may participate by providing:

(a) Ancillary Service:

(i) Regulation Up (Reg-Up) Service as a Controllable Load Resource capable of providing Primary Frequency Response;

(ii) Regulation Down (Reg-Down) Service as a Controllable Load Resource capable of providing Primary Frequency Response;

(iii) Responsive Reserve (RRS) as a Controllable Load Resource qualified for Security-Constrained Economic Dispatch (SCED) Dispatch and capable of providing Primary Frequency Response, or as a Load Resource controlled by high-set under-frequency relay;

[NPRR863: Insert paragraph (iv) below upon system implementation and renumber accordingly:]

(iv) ERCOT Contingency Reserve Service (ECRS) as a Controllable Load Resource qualified for SCED Dispatch and capable of providing Primary Frequency Response, or as a Load Resource that may or may not be controlled by high-set under-frequency relay;

(iv) Non-Spinning Reserve (Non-Spin) as a Controllable Load Resource qualified for SCED Dispatch or as a Load Resource that is not a

Controllable Load Resource and that is not controlled by under-frequency relay; and

(v) A Load Resource that is not a Controllable Load Resource cannot simultaneously provide Non-Spin and RRS in Real-Time;

(b) Energy in the form of Demand response from a Controllable Load Resource in Real-Time via SCED;

(c) Emergency Response Service (ERS) for hours in which the Load Resource does not have an Ancillary Service Resource Responsibility; and

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

(c) Emergency Response Service (ERS) for hours in which the Load Resource has a Resource Status of OUTL; and

(d) Voluntary Load response in Real-Time.

(2) Except for voluntary Load response and ERS, loads participating in any ERCOT market must be registered as a Load Resource and are subject to qualification testing administered by ERCOT.

(3) All ERCOT Settlements resulting from Load Resource participation are made only with the Qualified Scheduling Entity (QSE) representing the Load Resource.

(4) A QSE representing a Load Resource and submitting a bid to buy for participation in SCED, as described in Section 6.4.3.1, RTM Energy Bids, must represent the Load Serving Entity (LSE) serving the Load of the Load Resource. If the Load Resource is an Aggregate Load Resource (ALR), the QSE must represent the LSE serving the Load of all sites within the ALR.

(5) The Settlement Point for a Controllable Load Resource is its Load Zone Settlement Point. For an Energy Storage Resource (ESR), the Settlement Point for the charging Load withdrawn by the modeled Controllable Load Resource associated with the ESR is the Resource Node of the modeled Generation Resource associated with the ESR.

(6) QSEs shall not submit offers for Load Resources containing sites associated with a Dynamically Scheduled Resource (DSR).

[NPRR1000: Delete paragraph (6) above upon system implementation and renumber accordingly.]

(7) Each Resource Entity that represents one or more Load Resources shall ensure that each Load Resource it represents meets at least one of the following conditions:

(a) The Load Resource is not located behind an Electric Service Identifier (ESI ID) that corresponds to a Critical Load;

(b) The Load Resource is located behind an ESI ID that corresponds to a Critical Load, but the Load Resource is not a Critical Load and does not include a Critical Load; or

(c) The Load Resource is located behind an ESI ID that corresponds to a Critical Load, but electric service from the ERCOT System is not required for the provision of the critical service due to the availability of back-up generation or other technologies at the site.

(8) As a condition of obtaining and maintaining registration as a Load Resource, the Resource Entity for the Load Resource must have submitted an attestation, in a form deemed acceptable by ERCOT, stating that one of the conditions set forth in paragraph (7) above is true, and that if either of the conditions in paragraph (7)(b) or (7)(c) is true, then all of the Load Resource's offered Demand response capacity will be available if deployed by ERCOT during an emergency.

(9) Each QSE that represents one or more ERS Resources shall ensure that each ERS Resource identified in any ERS Submission Form submitted by the QSE meets at least one of the following conditions:

(a) The ERS Resource and each site within the ERS Resource are not located behind an ESI ID or unique meter identifier that corresponds to a Critical Load and are not used to support a Critical Load; or

(b) The ERS Resource or one or more sites within the ERS Resource are behind an ESI ID or unique meter identifier that corresponds to a Critical Load, but the ERS Resource and each site within the ERS Resource are not a Critical Load, do not include a Critical Load, and are not used to support a Critical Load; or

(c) The ERS Resource or one or more sites within the ERS Resource are behind an ESI ID or unique meter identifier that corresponds to a Critical Load, but electric service from the ERCOT System is not required for the provision of the critical service due to the availability of back-up generation or other technologies at the site, and neither the ERS Resource nor any site within the ERS Resource is used to support a Critical Load.

3.6.2 Decision Making Entity for a Resource

(1) Each Resource Entity that owns a Resource, except for a Load Resource that is not SCED qualified, shall submit a declaration to ERCOT, using Section 23, Form C, Managed Capacity Declaration, as to which Decision Making Entity (DME) has control of each of

its Resources. The declaration shall be signed by the Authorized Representative of the Resource Entity. In addition, each Resource Entity that owns a Resource, except for a Load Resource that is not SCED qualified, shall notify ERCOT of any known changes in that declaration no later than 14 days prior to the date that the change takes effect, or as soon as possible in a situation where the Resource Entity is unable to meet the 14-day Notice requirement. However, in no event may the Resource Entity inform ERCOT later than 72 hours before the date on which the change in DME takes effect. Upon ERCOT's request, each Resource Entity that owns a Resource, except for a Load Resource that is not SCED qualified, shall provide ERCOT with sufficient information or documentation to verify the DME's control of the Resource. ERCOT shall update the DME for a Resource effective the first Operating Hour of the Operating Day after ERCOT satisfactorily confirms the Resource Entity's most recent declaration, but not sooner than the effective date specified on the Resource Entity's most recent declaration.

3.7 Resource Parameters

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

[NPRR995 and NPRR1002: Replace applicable portions of paragraph (1) above with the following upon system implementation:]

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

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

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

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

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

3.7.1 Resource Parameter Criteria

3.7.1.1 Generation Resource Parameters

(1) Generation Resource Parameters that may be modified, with documented reason for change, by the QSE for immediate use upon ERCOT validation include:

(a) Normal Ramp Rate curve;

(b) Emergency Ramp Rate curve;

(c) Minimum On-Line time;

(d) Minimum Off-Line time;

(e) Maximum On-Line time;

(f) Maximum daily starts;

(g) Maximum weekly starts;

(h) Maximum weekly energy;

(i) Hot start time;

(j) Intermediate start time;

(k) Cold start time;

(l) Hot to intermediate time; and

(m) Intermediate to cold time.

3.7.1.2 Load Resource Parameters

(1) Resource Parameters that may be modified, with documented reason for change, by the QSE for immediate use upon ERCOT validation, which may be adjusted to reflect Distribution Losses in accordance with Section 8.1.1.2, General Capacity Testing Requirements, include the following for each of its Load Resources that is a non-Controllable Load Resource:

(a) Maximum interruption time;

(b) Maximum daily deployments;

(c) Maximum weekly deployments;

(d) Maximum weekly energy;

(e) Minimum notice time;

(f) Minimum interruption time; and

(g) Minimum restoration time.

(2) Resource Parameters that may be modified, with documented reason for change, by the QSE for immediate use upon ERCOT validation, which may be adjusted to reflect Distribution Losses in accordance with Section 8.1.1.2, include the following for each of its Controllable Load Resources, including Aggregate Load Resources (ALRs):

(a) Normal Ramp Rate curve;

(b) Emergency Ramp Rate curve;

(c) Maximum deployment time; and

(d) Maximum weekly energy.

(3) Resource Parameters submitted by a Resource Entity must also include, for each of its ALRs, mapping between the ALR and the individually metered Loads, by Electric Service Identifier (ESI ID) or, in the case of a Non-Opt-In Entity (NOIE), equivalent unique meter identifier, comprising the ALR.

[NPRR1002: Insert Section 3.7.1.3 below upon system implementation:]

3.7.1.3 Energy Storage Resource Parameters

(1) Resource Parameters for an ESR that may be modified, with documented reason for change, by the QSE for immediate use upon ERCOT validation include:

(a) Normal Ramp Rate curve; and

(b) Emergency Ramp Rate curve.

3.7.2 Changes in Resource Parameters with Operational Impacts

(1) The QSE representing each Resource shall have the responsibility to submit changes to Resource Parameters for those Resource Parameters related to the Current Operating Plan (COP), as described in Section 3.9, Current Operating Plan (COP), and to Real-Time

operations as described in Section 6, Adjustment Period and Real-Time Operations. If the QSE cancels a Resource Parameter submission, ERCOT will use as a default the Resource Parameter that is registered in the Network Operations Model.

3.7.3 Resource Parameter Validation

(1) ERCOT shall verify that changes to Resource Parameters submitted by the QSE representing the Resource comply with the Resource Registration Glossary. If a Resource Parameter is determined to be invalid, then ERCOT shall reject it and provide written notice to the QSE representing the Resource of the reason for the rejection.

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

[NPRR1026: Replace Section 3.8 above with the following upon system implementation:]

3.8 Special Considerations

3.8.1 Split Generation Resources

(1) When a generation meter is split, as provided for in Section 10.3.2.1, Generation Resource Meter Splitting, two or more independent Generation Resources must be created in the ERCOT Network Operations Model according to Section 3.10.7.2, Modeling of Resources and Transmission Loads, to function in all respects as Split Generation Resources in ERCOT System operation. A Combined Cycle Train may not be registered in ERCOT as a Split Generation Resource. A Distribution Generation Resource (DGR) or Distribution Energy Storage Resource (DESR) may not be registered in ERCOT as a Split Generation Resource.

(2) Each Qualified Scheduling Entity (QSE) representing a Split Generation Resource shall collect and shall submit to ERCOT the Resource Parameters defined under Section 3.7, Resource Parameters, for the Split Generation Resource it represents. The parameters provided must be consistent with the parameters submitted by each other QSE that represents a Split Generation Resource from the same Generation Resource. The parameters submitted for each Split Generation Resource for limits and ramp rates must be according to the capability of the Split Generation Resource represented by the QSE. Startup and shutdown times, time to change status and number of starts must be identical for all the Split Generation Resources from the same Generation Resource submitted by each QSE. ERCOT shall review data submitted by each QSE representing Split Generation Resources for consistency and notify each QSE of any errors.

(3) Each Split Generation Resource may be represented by a different QSE. The Resource Entities that own or control the Split Generation Resources from a single Generation Resource must designate a Master QSE. Each QSE representing a Split Generation Resource must comply in all respects to the requirements of a Generation Resource specified under these Protocols.

(4) The Master QSE shall:

(a) Serve as the Single Point of Contact for the Generation Resource, as required by Section 3.1.4.1, Single Point of Contact;

(b) Provide real-time telemetry for the total Generation Resource, as specified in Section 6.5.5.2, Operational Data Requirements; and

(c) Receive Verbal Dispatch Instructions (VDIs) from ERCOT, as specified in Section 6.5.7.8, Dispatch Procedures.

(5) Each QSE is responsible for representing its Split Generation Resource in its Current Operating Plan (COP). During the Reliability Unit Commitment (RUC) Study Periods, any conflict in the Resource Status of a Split Generation Resource in the COP is resolved according to the following:

(a) If a Split Generation Resource has a Resource Status of OUT for any hour in the COP, then any other QSEs' COP entries for their Split Generation Resources from the same Generation Resource are also considered unavailable for the hour;

(b) If the QSEs for all Split Generation Resources from the same Generation Resource have submitted a COP and at least one of the QSEs has an On-Line Resource Status in a given hour, then the status for all Split Generation Resources for the Generation Resource is considered to be On-Line for that hour, except if any of the QSEs has indicated in the COP a Resource Status of OUT.

(6) Each QSE representing a Split Generation Resource shall update its individual Resource Status appropriately.

(7) Each QSE representing a Split Generation Resource may independently submit Energy Offer Curves and Three-Part Supply Offers. ERCOT shall treat each Split Generation Resource offer as a separate offer, except that all Split Generation Resources in a single Generation Resource must be committed or decommitted together.

[NPRR1007: Replace paragraph (7) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(7) Each QSE representing a Split Generation Resource may independently submit Energy Offer Curves, Ancillary Service Offers, and Three-Part Supply Offers. ERCOT shall treat each Split Generation Resource offer as a separate offer, except that all Split

Generation Resources in a single Generation Resource must be committed or decommitted together.

(8) Each QSE submitting verifiable cost data to ERCOT shall coordinate among all owners of a single Generation Resource to provide individual Split Generation Resource data consistent with the total verifiable cost of the entire Generation Resource. ERCOT may compare the total verifiable costs with other similarly situated Generation Resources to determine the reasonability of the cost.

3.8.2 Combined Cycle Generation Resources

(1) ERCOT shall assign a logical Resource Node for use in the Day-Ahead Market (DAM), RUC, Supplemental Ancillary Services Market (SASM), Security-Constrained Economic Dispatch (SCED) and Load Frequency Control (LFC) to each registered Combined Cycle Train. Each Combined Cycle Generation Resource registered in the Combined Cycle Train will be mapped to the Combined Cycle Train logical Resource Node for the purposes of evaluating and settling each Combined Cycle Generation Resource's Three-Part Supply Offer and Ancillary Service Offer in the DAM, RUC and SCED. Each generation unit identified in the Combined Cycle Train registration for a Combined Cycle Generation Resource configuration will be mapped to its designated Resource Node as determined in accordance with these Protocols and the Other Binding Document titled "Procedure for Identifying Resource Nodes."

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

(1) ERCOT shall assign a logical Resource Node for use in the Day-Ahead Market (DAM), RUC, Security-Constrained Economic Dispatch (SCED) and Load Frequency Control (LFC) to each registered Combined Cycle Train. Each Combined Cycle Generation Resource registered in the Combined Cycle Train will be mapped to the Combined Cycle Train logical Resource Node for the purposes of evaluating and settling each Combined Cycle Generation Resource's Three-Part Supply Offer and Ancillary Service Offer in the DAM, RUC and SCED. Each generation unit identified in the Combined Cycle Train registration for a Combined Cycle Generation Resource configuration will be mapped to its designated Resource Node as determined in accordance with these Protocols and the Other Binding Document titled "Procedure for Identifying Resource Nodes."

(2) If any of the generation units, designated in the Combined Cycle Train registration as a primary generation unit in a Combined Cycle Generation Resource, is isolated from the ERCOT Transmission Grid because of a transmission Outage reported in the Outage Scheduler, the DAM and RUC applications shall select an alternate generation unit for use in the application.

(3) Three-Part Supply Offers submitted for a Combined Cycle Generation Resource will be modeled as High Reasonability Limit (HRL)-weighted injections at the Resource Connectivity Nodes of the associated Generation Resources. ERCOT shall use the logical Resource Node to settle these offers.

(4) In the DAM and RUC, ERCOT shall model the energy injection from each generation unit registered to the Combine Cycle Generation Resource designated in a Three-Part Supply Offer as follows:

(a) The energy injection for each generation unit registered in the Combined Cycle Generation Resource designated in a Three-Part Supply Offer shall be the offered energy injection for the selected price point on the Three-Part Supply Offer's Energy Offer Curve times a weight factor as determined in paragraph (4)(b) below.

(b) The weight factor for each generation unit registered in a Combined Cycle Generation Resource shall be the generation unit's HRL, as specified in the Resource Registration data provided to ERCOT pursuant to Planning Guide Section 6.8.2, Resource Registration Process, divided by the total of all HRL values for the generation units registered in the designated Combined Cycle Generation Resource.

(5) In the Network Operations Network Models used in the DAM, RUC and SCED applications, each generation unit identified in the Combined Cycle Train registration must be modeled at its Resource Connectivity Node.

(6) For Ancillary Services offered and provided from Combined Cycle Generation Resources, ERCOT shall apply, without exception, the same rules and requirements specified in these Protocols for the DAM, RUC and Adjustment Period and Real-Time markets that apply to Ancillary Services provided from any other Generation Resources.

(a) ERCOT systems shall determine the High and Low Ancillary Service Limits (HASL and LASL) for a Combined Cycle Generation Resource as follows:

(i) In Real Time, relative to the telemetered High Sustained Limit (HSL) for the Combined Cycle Generation Resource, or

(ii) During the DAM and RUC study periods, relative to the HSL in the COP.

(b) The QSE shall assure that the Combined Cycle Generation Resource designated as On-Line through telemetry or in the COP can meet its Ancillary Service Resource Responsibility.

[NPRR1007: Replace paragraph (6) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(6) For Ancillary Services offered and provided from Combined Cycle Generation Resources, ERCOT shall apply, without exception, the same rules and requirements specified in these Protocols for the DAM, RUC and Adjustment Period and Real-Time markets that apply to Ancillary Services provided from any other Generation Resources.

(a) ERCOT systems shall determine the operating limits for a Combined Cycle Generation Resource as follows:

(i) In Real-Time, relative to the telemetered capacity limits, ramp rates, and Ancillary Service capabilities for the Combined Cycle Generation Resource;

(ii) During the DAM study period, relative to the HSL in the COP; or

(iii) During the RUC Study Period, relative to the capacity limits and Ancillary Service capabilities in the COP.

3.8.3 Quick Start Generation Resources

(1) The QSE for a Quick Start Generation Resource (QSGR) that is available for deployment by SCED shall set the COP Resource Status to OFFQS, and the COP Low Sustained Limit (LSL) and COP HSL values to the expected sustainable LSL and HSL for the QSGR for the hour. If the QSGR is providing Non-Spinning Reserve (Non-Spin) service, then the Ancillary Service Resource Responsibility for Non-Spin shall be set to the Resource's QSE-assigned Non-Spin responsibility in the COP.

[NPRR863 and NPRR1007: Replace applicable portions of paragraph (1) above with the following upon system implementation for NPRR863; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007:]

(1) The QSE for a Quick Start Generation Resource (QSGR) that is available for deployment by SCED and awarding of ERCOT Contingency Reserve Service (ECRS) and Non-Spinning Reserve (Non-Spin), if qualified and capable, shall set the COP Resource Status to OFFQS, and the COP Low Sustained Limit (LSL) and COP HSL values to the expected sustainable LSL and HSL for the QSGR for the hour.

(2) The QSGR that is available for deployment by SCED shall telemeter a Resource Status of OFFQS and a LSL of zero prior to receiving a deployment instruction from SCED. This status is necessary in order for SCED to recognize that the Resource can be Dispatched. The status of the breaker shall be open and the output of the Resource shall be zero in order for the State Estimator to correctly assess the state of the system. After being deployed for energy from SCED, the Resource shall telemeter an LSL equal to or less than the Resource's actual output until the Resource has ramped to its physical LSL.

After reaching its physical LSL, the QSGR shall telemeter an LSL that reflects its physical LSL. The QSGR that is providing Off-Line Non-Spin shall always telemeter an Ancillary Service Resource Responsibility for Non-Spin to reflect the Resource's Non-Spin obligation and shall always telemeter an Ancillary Service Schedule for Non-Spin of zero to make the capacity available for SCED.

[NPRR1007: Replace paragraph (2) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(2) The QSGR that is available for deployment by SCED and awarding of ECRS and Non-Spin, if qualified and capable, shall telemeter a Resource Status of OFFQS and a LSL of zero prior to receiving a deployment instruction from SCED. This status is necessary in order for SCED to recognize that the Resource can be Dispatched and/or awarded ECRS and Non-Spin. The status of the breaker shall be open and the output of the Resource shall be zero in order for the State Estimator to correctly assess the state of the system. After being deployed for energy from SCED, the Resource shall telemeter an LSL equal to or less than the Resource's actual output until the Resource has ramped to its physical LSL. After reaching its physical LSL, the QSGR shall telemeter an LSL that reflects its physical LSL.

(3) A QSGR with a telemeter breaker status of open and a telemeter Resource Status OFFQS shall not provide Regulation Service or Responsive Reserve (RRS).

(4) ERCOT shall adjust the QSGR's Mitigated Offer Cap (MOC) curve as described in Section 4.4.9.4.1, Mitigated Offer Cap.

(5) For a QSGR that is physically Off-Line, the Resource Entity shall submit a Normal Ramp Rate curve and Emergency Ramp Rate curve indicating QSGR's ability to reach its ten-minute tested output from zero output in five minutes. This is necessary to prevent SCED from deploying multiple QSGRs due to ramp limitation in the first five minutes after being Dispatched by SCED. QSGRs shall be exempt from Base Point Deviation Charges as described in Section 6.6.5.3, Resources Exempt from Deviation Charges.

[NPRR1007: Replace paragraph (5) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(5) For a QSGR that is physically Off-Line, the Resource Entity shall submit a Normal Ramp Rate curve and Emergency Ramp Rate curve indicating QSGR's ability to reach its ten-minute tested output from zero output in five minutes. This is necessary to prevent SCED from deploying multiple QSGRs due to ramp limitation in the first five minutes after being Dispatched by SCED. QSGRs shall be exempt from Set Point Deviation Charges as described in Section 6.6.5.3, Resources Exempt from Deviation Charges.

(6) Any hour in which the QSE for the QSGR has shown the Resource as available for SCED Dispatch as described in this Section 3.8.3 is considered a QSE-Committed Interval.

(7) QSEs must submit and maintain an Energy Offer Curve for their QSGRs for all hours in which the COP Resource Status is submitted as OFFQS. If a valid Energy Offer Curve or an Output Schedule does not exist for any QSGR for which a Resource Status of OFFQS is telemetered at the end of the Adjustment Period, then ERCOT shall notify the QSE and set the Output Schedule equal to the then-current telemetered output of the Resource until an Output Schedule or Energy Offer Curve is submitted in a subsequent Adjustment Period. For use as SCED inputs, ERCOT shall create proxy Energy Offer Curves for the Resource as described in paragraph (4) of Section 6.5.7.3, Security Constrained Economic Dispatch.

(8) Other than for the potential decommitment of a QSGR as described in Section 3.8.3.1, Quick Start Generation Resource Decommitment Decision Process, following a SCED QSGR deployment, the QSGR is expected to follow the SCED Base Points.

3.8.3.1 Quick Start Generation Resource Decommitment Decision Process

(1) For purposes of determining whether SCED needs a QSGR to continue to generate per paragraph (3) of Section 6.6.9, Emergency Operations Settlement, the QSE representing the QSGR shall telemeter an LSL of zero for at least one but no more than two non-consecutive SCED executions in each Operating Hour during which the QSGR is operating with a SCED Base Point equal to its registered LSL and shall telemeter Normal and Emergency Ramp Rates indicating that the QSGR can be Dispatched to zero output in a single SCED interval.

   (a) If the SCED issued Base Point for the QSGR is non-zero in the interval where a zero LSL has been telemetered by the QSE, then the QSGR is deemed needed by SCED and the QSE shall immediately resume telemetering an LSL equal to the physical LSL and continue to operate the unit following subsequent Base Points.

   (b) If the Base Point is zero, then the QSE will decommit the QSGR using normal operating practices.

   (c) If at any point during the period in which the QSGR is in SHUTDOWN mode, the QSGR Locational Marginal Price (LMP) is greater than or equal to the Energy Offer Curve price, capped per Section 4.4.9.4.1, Mitigated Offer Cap, the QSE may reverse the decommitment process, if possible and make the QSGR available for SCED following normal operating practices.

3.8.4 Generation Resources Operating in Synchronous Condenser Fast-Response Mode

(1) A QSE is considered to have performed for the amount of its RRS obligation for the MW amount provided by a Generation Resource operating in synchronous condenser fast-response mode and triggered by an under-frequency relay device at the frequency set

point specified in paragraph (3)(c) of Section 3.18, Resource Limits in Providing Ancillary Service, without corresponding RRS deployment by ERCOT. This provision applies only for the duration when RRS MW is deployed by automatic under-frequency relay action.

3.8.5 Energy Storage Resources

(1) The Resource Entity and QSE representing an Energy Storage Resource (ESR) which is jointly registered with ERCOT as a Generation Resource and a Controllable Load Resource, pursuant to paragraph (6) of Section 16.5, Registration of a Resource Entity, are responsible for following all requirements in these Protocols associated with Generation Resources and Controllable Load Resources.

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

(1) For the purposes of all ERCOT Protocols and Other Binding Documents, all requirements that apply to Generation Resources and Controllable Load Resources shall be understood to apply to Energy Storage Resources (ESRs) to the same extent, except where the Protocols explicitly provide otherwise.

(2) A QSE representing an ESR may update the telemetered HSL and/or Maximum Power Consumption (MPC) for the ESR in Real-Time to ensure the ability to meet the ESR's full Ancillary Service Resource Responsibility for the current Operating Hour. This provision only applies when the MOC for an ESR is set at the System-Wide Offer Cap (SWCAP) pursuant to paragraph (1)(b) of Section 4.4.9.4.1, Mitigated Offer Cap.

[NPRR1075: Delete paragraph (2) above upon system implementation of the Real-Time Co-Optimization (RTC) project.]

(3) A QSE representing an ESR may update the telemetered HSL and/or MPC for the ESR in Real-Time to reflect state of charge limitations.

[NPRR1075: Replace paragraph (3) above with the following upon system implementation of NPRR1014:]

(3) A QSE representing an ESR may update the telemetered HSL and/or LSL for the ESR in Real-Time to reflect state of charge limitations.

(4) A QSE representing an ESR co-located with a Generation Resource may reduce the telemetered MPC of the Controllable Load Resource modeled to represent the charging side of the ESR when self-charging using output from the Generation Resource. Such reduction in MPC shall be equal to the MW level of self-charge.

[NPRR1075: Replace paragraph (4) above with the following upon system implementation of NPRR1014:]

(4) A QSE representing an ESR co-located with a Generation Resource may update the telemetered LSL of the ESR when self-charging (using output from the Generation Resource). The updated LSL shall be equal to the MW level of self-charge.

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

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

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

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

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

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

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

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

[NPRR995: Replace paragraph (2) above with the following upon system implementation:]

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

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

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

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

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

[NPRR1026 and NPRR1077: Insert applicable portions of Section 3.8.7 below upon system implementation:]

3.8.7 Self-Limiting Facility

(1) A Resource Entity or Interconnecting Entity (IE) for a Self-Limiting Facility may establish a MW Injection or MW Withdrawal limit by submitting an attestation in a form designated by ERCOT through the Resource Registration process. The Resource Entity or IE shall simultaneously provide a copy of the attestation to the interconnecting Transmission and/or Distribution Service Provider (TDSP). All registered generators or Energy Storage Systems (ESSs) within a Self-Limiting Facility shall be represented by a single Resource Entity and a single QSE.

(2) A Self-Limiting Facility shall not inject or withdraw power in excess of its established MW Injection limit or its established MW Withdrawal limit.

(3) On a monthly basis, ERCOT will report to the Reliability Monitor and IMM any instance where a Self-Limiting Facility's actual MW Injections exceeded the MW Injection limit or where actual MW Withdrawals exceeded the MW Withdrawal limit established in the Resource Registration data for the Self-Limiting Facility, based on the telemetry of the injection and withdrawal values provided by the QSE for the registered

generator or ESS in the Self-Limiting Facility, as described in Section 3.9.1, Current Operating Plan (COP) Criteria, and in Section 6.5.5.2, Operational Data Requirements, or based on the meter data at the Point of Interconnection (POI) or Point of Common Coupling (POCC) for the Self-Limiting Facility.

(4) If requested by ERCOT, the relevant QSE shall provide meter data to confirm whether the established limits for a Self-Limiting Facility were violated.

(5) If ERCOT determines that a Self-Limiting Facility connected at transmission voltage has exceeded either its MW Injection limit or its MW Withdrawal limit established in the Resource Registration data by more than the greater of 5 MW or 3% of the limit, the Self-Limiting Facility shall submit a new generation interconnection request based on the installed MW capacity of the individual Resource(s) and shall deregister as a Self-Limiting Facility at the completion of the generation interconnection process. The Self-Limiting Facility shall be subject to the established MW Injection limit and any established MW Withdrawal limit until the generation interconnection process has been completed.

(6) A Distribution Service Provider (DSP) may limit injections and withdrawals from any Generation Resource, Settlement Only Generator (SOG), or ESR based on Resource Registration data and the interconnection agreement between the DSP and the IE or Resource Entity. In that case, the IE or Resource Entity shall submit the attestation required by paragraph (1) above, and shall be considered a Self-Limiting Facility.

(7) If ERCOT determines that a Self-Limiting Facility connected at distribution voltage has exceeded either its MW Injection limit or its MW Withdrawal limit established in the Resource Registration data, the Self-Limiting Facility shall submit a new generation interconnection request based on the installed MW capacity of the individual Resource(s) and shall be deregistered as a Self-Limiting Facility at the completion of the generation interconnection process. The Self-Limiting Facility shall be subject to any MW Injection or MW Withdrawal limit until the generation interconnection process has been completed.

(8) The interconnecting TDSP, at its sole discretion, may use relaying to ensure a Self-Limiting Facility does not inject or withdraw energy in excess of its MW Injection or MW Withdrawal limits in order to protect the TDSP's limiting element(s).

[NPRR1029 and NPRR1111: Insert applicable portions of Section 3.8.8 below upon system implementation for NPRR1029; or upon system implementation of SCR819 for NPRR1111:]

3.8.8 DC-Coupled Resources

(1) A DC-Coupled Resource shall be treated in the same manner as an Energy Storage Resource (ESR) for the purposes of determining Set Point Deviation Charges, as described in Section 6.6.5, Set Point Deviation Charge, and Energy Storage Resource

Energy Deployment Performance (ESREDP), as described in Section 8.1.1.4.1, Regulation Service and Generation Resource/Controllable Load Resource/Energy Storage Resource Energy Deployment Performance, under one of the following conditions:

(a) The Resource was awarded Ancillary Service;

(b) The Resource's instantaneous MW Injection or MW Withdrawal includes non-zero MW from the ESS component of the DC-Coupled Resource; or

(c) The Resource's telemetered HSL or LSL includes the ESS capability.

(2) At all other times, a DC-Coupled Resource shall be treated in the same manner as an IRR for the purposes of determining Set Point Deviation Charges, as described in Section 6.6.5, and ESREDP, as described in Section 8.1.1.4.1.

(3) A QSE representing a DC-Coupled Resource that does not meet any of the conditions in paragraph (1) above:

(a) Shall set the Resource's telemetered HSL equal to the current net output capability of the intermittent renewable generation component of the DC-Coupled Resource; and

(b) Shall set the Resource's output at or below the SCED Base Point telemetered by ERCOT if the Resource receives a flag indicating that SCED has dispatched it below the Resource's HDL used by SCED or that it has been instructed not to exceed its Base Point.

3.9 Current Operating Plan (COP)

(1) Each Qualified Scheduling Entity (QSE) that represents a Resource must submit a Current Operating Plan (COP) under this Section.

(2) ERCOT shall use the information provided in the COP to calculate the High Ancillary Service Limit (HASL) and Low Ancillary Service Limit (LASL) for each Resource for the Reliability Unit Commitment (RUC) processes.

[NPRR1007: Replace paragraph (2) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(2) ERCOT shall use the information provided in the COP to calculate operating limits and Ancillary Service capabilities for each Resource for the Reliability Unit Commitment (RUC) processes.

(3) ERCOT shall monitor the accuracy of each QSE's COP as outlined in Section 8, Performance Monitoring.

(4) A QSE must notify ERCOT that it plans to have a Resource On-Line by means of the COP using the Resource Status codes listed in paragraph (5)(b)(i) of Section 3.9.1, Current Operating Plan (COP) Criteria. The QSE must show the Resource as On-Line with a Resource Status of ONRUC, indicating a RUC process committed the Resource for all RUC-Committed Intervals. A QSE may only use a RUC-committed Resource during that Resource's RUC-Committed Interval to meet the QSE's Ancillary Service Supply Responsibility if the Resource has been committed by the RUC process to provide Ancillary Service.

(5) To reflect changes to a Resource's capability, each QSE shall report by exception, changes to the COP for all hours after the Operating Period through the rest of the Operating Day.

(6) When a QSE updates its COP to show changes in Resource Status, the QSE shall update for each On-Line Resource, either an Energy Offer Curve under Section 4.4.9, Energy Offers and Bids, or Output Schedule under Section 6.4.2, Output Schedules.

(7) Each QSE, including QSEs representing Reliability Must-Run (RMR) Units, Firm Fuel Supply Service Resources (FFSSRs), or Black Start Resources, shall submit a revised COP reflecting changes in Resource availability as soon as reasonably practicable, but in no event later than 60 minutes after the event that caused the change.

(8) Each QSE representing a Qualifying Facility (QF) must submit a Low Sustained Limit (LSL) that represents the minimum energy available, in MW, from the unit for economic dispatch based on the minimum stable steam delivery to the thermal host plus a justifiable reliability margin that accounts for changes in ambient conditions.

(9) When ERCOT issues a communication in the form of an Operating Condition Notice (OCN), Advisory, Watch, or Emergency Notice due to forecasted or actual cold or hot weather, for each Generation Resource and Energy Storage Resource (ESR) a QSE represents, the QSE shall update the COP, Real-Time telemetry, and Outage or derate reporting to reflect any Resource-specific operating limitations based on: (i) capability and availability; (ii) fuel supply or inventory concerns, including fuel switching capabilities; or (iii) environmental constraints and the impact on the Generation Resource or ESR due to the weather conditions. QSEs shall provide these updates in accordance with Sections 3.1.4, Communications Regarding Resource and Transmission Facility Outages; 3.10.7.5, Telemetry Requirements; 3.9, Current Operating Plan (COP); 3.9.1, Current Operating Plan (COP) Criteria; and Nodal Operating Guide Section 7.3, Telemetry.

3.9.1 Current Operating Plan (COP) Criteria

(1) Each QSE that represents a Resource must submit a COP to ERCOT that reflects expected operating conditions for each Resource for each hour in the next seven Operating Days.

(2) Each QSE that represents a Resource shall update its COP reflecting changes in availability of any Resource as soon as reasonably practicable, but in no event later than 60 minutes after the event that caused the change.

[NPRR1085: Replace paragraph (2) above with the following upon system implementation:]

(2) Each QSE that represents a Resource shall update its COP reflecting changes in availability of any Resource as soon as reasonably practicable, but in no event later than 60 minutes after the event that caused the change. Each QSE shall timely update its COP unless in the reasonable judgment of the QSE, such compliance would create an undue threat to safety, undue risk of bodily harm, or undue damage to equipment. The QSE is excused from updating the COP only for so long as the undue threat to safety, undue risk of bodily harm, or undue damage to equipment exists. The time for updating the COP begins once the undue threat to safety, undue risk of bodily harm, or undue damage to equipment no longer exists.

(3) The Resource capacity in a QSE's COP must be sufficient to supply the Ancillary Service Supply Responsibility of that QSE.

[NPRR1007, NPRR1014, and NPRR1029: Replace applicable portions of paragraph (3) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029:]

(3) Each QSE that represents a Resource shall update its COP to reflect the ability of the Resource to provide each Ancillary Service by product and sub-type.

(4) Load Resource COP values may be adjusted to reflect Distribution Losses in accordance with Section 8.1.1.2, General Capacity Testing Requirements.

(5) A COP must include the following for each Resource represented by the QSE:

(a) The name of the Resource;

(b) The expected Resource Status:

(i) Select one of the following for Generation Resources synchronized to the ERCOT System that best describes the Resource's status. Unless otherwise provided below, these Resource Statuses are to be used for COP and/or Real-Time telemetry purposes, as appropriate.

(A) ONRUC – On-Line and the hour is a RUC-Committed Hour;

(B) ONREG – On-Line Resource with Energy Offer Curve providing Regulation Service;

[NPRR1007, NPRR1014, and NPRR1029: Delete item (B) above upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029; and renumber accordingly.]

(C) ON – On-Line Resource with Energy Offer Curve;

(D) ONDSR – On-Line Dynamically Scheduled Resource (DSR);

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

(E) ONOS – On-Line Resource with Output Schedule;

(F) ONOSREG – On-Line Resource with Output Schedule providing Regulation Service;

[NPRR1007, NPRR1014, and NPRR1029: Delete item (F) above upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029; and renumber accordingly.]

(G) ONDSRREG – On-Line DSR providing Regulation Service;

[NPRR1000, NPRR1007, NPRR1014, and NPRR1029: Delete item (G) above upon system implementation for NPRR1000, NPRR1014, or NPRR1029; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; and renumber accordingly.]

(H) FRRSUP – Available for Dispatch of Fast Responding Regulation Service (FRRS). This Resource Status is only to be used for Real-Time telemetry purposes;

[NPRR1007, NPRR1014, and NPRR1029: Delete item (H) above upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 and NPRR1029; and renumber accordingly.]

(I) ONTEST – On-Line blocked from Security-Constrained Economic Dispatch (SCED) for operations testing (while ONTEST, a Generation Resource may be shown on Outage in the Outage Scheduler);

(J) ONEMR – On-Line EMR (available for commitment or dispatch only for ERCOT-declared Emergency Conditions; the QSE may appropriately set LSL and High Sustained Limit (HSL) to reflect operating limits);

(K) ONRR – On-Line as a synchronous condenser providing Responsive Reserve (RRS) but unavailable for Dispatch by SCED and available for commitment by RUC;

[NPRR1007, NPRR1014, and NPRR1029: Delete item (K) above upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029; and renumber accordingly.]

(L) ONECRS – On-Line as a synchronous condenser providing ERCOT Contingency Response Service (ECRS) but unavailable for Dispatch by SCED and available for commitment by RUC;

[NPRR1007, NPRR1014, and NPRR1029: Delete item (L) above upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029; and renumber accordingly.]

(M) ONOPTOUT – On-Line and the hour is a RUC Buy-Back Hour;

(N) SHUTDOWN – The Resource is On-Line and in a shutdown sequence, and has no Ancillary Service Obligations other than Off-Line Non-Spinning Reserve (Non-Spin) which the Resource will provide following the shutdown. This Resource Status is only to be used for Real-Time telemetry purposes;

[NPRR1007, NPRR1014, and NPRR1029: Replace paragraph (N) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029:]

(N) SHUTDOWN – The Resource is On-Line and in a shutdown sequence, and is not eligible for an Ancillary Service award. This Resource Status is only to be used for Real-Time telemetry purposes;

(O) STARTUP – The Resource is On-Line and in a start-up sequence and has no Ancillary Service Obligations. This Resource Status is only to be used for Real-Time telemetry purposes;

[NPRR1007, NPRR1014, and NPRR1029: Replace paragraph (O) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029:]

(O) STARTUP – The Resource is On-Line and in a start-up sequence and is not eligible for an Ancillary Service award, unless coming On-Line in response to a manual deployment of ERCOT Contingency Reserve Service (ECRS) or Non-Spinning Reserve (Non-Spin). This Resource Status is only to be used for Real-Time telemetry purposes;

(P) OFFQS – Off-Line but available for SCED deployment. Only qualified Quick Start Generation Resources (QSGRs) may utilize this status; and

[NPRR1007, NPRR1014, and NPRR1029: Replace paragraph (P) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029:]

(P) OFFQS – Off-Line but available for SCED deployment and to provide ECRS and Non-Spin, if qualified and capable. Only qualified Quick Start Generation Resources (QSGRs) may utilize this status;

(Q) ONFFRRRS – Available for Dispatch of RRS providing Fast Frequency Response (FFR) from Generation Resources. This Resource Status is only to be used for Real-Time telemetry purposes;

[NPRR1015: Replace paragraph (Q) above with the following upon system implementation of NPRR863:]

(Q) ONFFRRRS – Available for Dispatch of RRS when providing Fast Frequency Response (FFR) from Generation Resources.

This Resource Status is only to be used for Real-Time telemetry purposes. A Resource with this Resource Status may also be providing Ancillary Services other than FFR;

[NPRR1007, NPRR1014, and NPRR1029: Delete item (Q) above upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029; and renumber accordingly.]

[NPRR1007, NPRR1014, NPRR1029, and NPRR1085: Insert applicable portions of items (K) and (L) below upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014, NPRR1029, or NPRR1085:]

(K) ONSC – Resource is On-Line operating as a synchronous condenser and available to provide Responsive Reserve (RRS) and ECRS, if qualified and capable, and for commitment by RUC, but is unavailable for Dispatch by SCED. For SCED, Resource Base Points will be set equal to the telemetered net real power of the Resource available at the time of the SCED execution; and

(L) ONHOLD – Resource is On-Line but temporarily unavailable for Dispatch by SCED or Ancillary Service awards. This Resource Status is only to be used for Real-Time telemetry purposes. For SCED, Resource Base Points will be set equal to the telemetered net real power of the Resource available at the time of the SCED execution.

(ii) Select one of the following for Off-Line Generation Resources not synchronized to the ERCOT System that best describes the Resource's status. These Resource Statuses are to be used for COP and/or Real-Time telemetry purposes, as appropriate.

(A) OUT – Off-Line and unavailable, or not connected to the ERCOT System and operating in a Private Microgrid Island (PMI);

(B) OFFNS – Off-Line but reserved for Non-Spin;

[NPRR1007, NPRR1014, and NPRR1029: Delete item (B) above upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029; and renumber accordingly.]

(C) OFF – Off-Line but available for commitment in the Day-Ahead Market (DAM) and RUC;

[NPRR1007, NPRR1014, and NPRR1029: Replace item (C) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029:]

(B) OFF – Off-Line but available for commitment in the Day-Ahead Market (DAM), RUC, and providing Non-Spin, if qualified and capable;

(D) EMR – Available for commitment as a Resource contracted by ERCOT under Section 3.14.1, Reliability Must Run, or under paragraph (4) of Section 6.5.1.1, ERCOT Control Area Authority, or available for commitment only for ERCOT-declared Emergency Condition events; the QSE may appropriately set LSL and HSL to reflect operating limits;

(E) EMRSWGR – Switchable Generation Resource (SWGR) operating in a non-ERCOT Control Area, or in the case of a Combined Cycle Train with one or more SWGRs, a configuration in which one or more of the physical units in that configuration are operating in a non-ERCOT Control Area.

(iii) Select one of the following for Load Resources. Unless otherwise provided below, these Resource Statuses are to be used for COP and/or Real-Time telemetry purposes.

(A) ONRGL – Available for Dispatch of Regulation Service by Load Frequency Control (LFC) and, for any remaining Dispatchable capacity, by SCED with a Real-Time Market (RTM) Energy Bid;

(B) FRRSUP – Available for Dispatch of FRRS by LFC and not Dispatchable by SCED. This Resource Status is only to be used for Real-Time telemetry purposes;

(C) FRRSDN - Available for Dispatch of FRRS by LFC and not Dispatchable by SCED. This Resource Status is only to be used for Real-Time telemetry purposes;

(D) ONCLR – Available for Dispatch as a Controllable Load Resource by SCED with an RTM Energy Bid;

(E) ONRL – Available for Dispatch of RRS or Non-Spin, excluding Controllable Load Resources;

[NPRR1007, NPRR1014, and NPRR1029: Delete items (A)-(E) above upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029; and renumber accordingly.]

(F) ONECL – Available for Dispatch of ECRS, excluding Controllable Load Resources;

[NPRR1007, NPRR1014, and NPRR1029: Delete item (F) above upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029; and renumber accordingly.]

(G) OUTL – Not available;

(H) ONFFRRRSL – Available for Dispatch of RRS, excluding Controllable Load Resources. This Resource Status is only to be used for Real-Time telemetry purposes;

[NPRR1015: Replace paragraph (H) above with the following upon system implementation of NPRR863:]

(H) ONFFRRRSL – Available for Dispatch of RRS when providing FFR, excluding Controllable Load Resources. This Resource Status is only to be used for Real-Time telemetry purposes;

[NPRR1007, NPRR1014, and NPRR1029: Delete item (H) above upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029.]

[NPRR1007, NPRR1014, NPRR1029: Insert item (B) below upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029:]

(B) ONL – On-Line and available for Dispatch by SCED or providing Ancillary Services.

[NPRR1014 or NPRR1029: Insert applicable portions of paragraph (iv) below upon system implementation:]

(iv) Select one of the following for Energy Storage Resources (ESRs). Unless otherwise provided below, these Resource Statuses are to be used for COP and Real-Time telemetry purposes:

(A) ON – On-Line Resource with Energy Bid/Offer Curve;

(B) ONOS – On-Line Resource with Output Schedule;

(C) ONTEST – On-Line blocked from SCED for operations testing (while ONTEST, an Energy Storage Resource (ESR) may be shown on Outage in the Outage Scheduler);

(D) ONEMR – On-Line EMR (available for commitment or dispatch only for ERCOT-declared Emergency Conditions; the QSE may appropriately set LSL and High Sustained Limit (HSL) to reflect operating limits);

(E) ONHOLD – Resource is On-Line but temporarily unavailable for Dispatch by SCED or Ancillary Service awards. ESRs shall not be discharging into or charging from the grid. This Resource Status is only to be used for Real-Time telemetry purposes; and

(F) OUT – Off-Line and unavailable, or not connected to the ERCOT System and operating in a Private Microgrid Island (PMI);

(c) The HSL;

(i) For Load Resources other than Controllable Load Resources, the HSL should equal the expected power consumption;

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

(ii) For ESRs, the HSL may be negative;

(d) The LSL;

(i) For Load Resources other than Controllable Load Resources, the LSL should equal the expected Low Power Consumption (LPC);

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

(ii) For ESRs, the LSL may be positive;

(e) The High Emergency Limit (HEL);

(f) The Low Emergency Limit (LEL); and

(g) Ancillary Service Resource Responsibility capacity in MW for:

[NPRR1007, NPRR1014, and NPRR1029: Replace applicable portions of item (g) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029:]

(g) Ancillary Service capability in MW for each product and sub-type.

(i) Regulation Up (Reg-Up);

(ii) Regulation Down (Reg-Down);

(iii) RRS;

(iv) ECRS; and

(v) Non-Spin.

[NPRR1007, NPRR1014, and NPRR1029: Delete items (i)-(v) above upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029.]

(6) For Combined Cycle Generation Resources, the above items are required for each operating configuration. In each hour only one Combined Cycle Generation Resource in a Combined Cycle Train may be assigned one of the On-Line Resource Status codes described above.

(a) During a RUC study period, if a QSE's COP reports multiple Combined Cycle Generation Resources in a Combined Cycle Train to be On-Line for any hour, then until the QSE corrects its COP, the On-Line Combined Cycle Generation Resource with the largest HSL is considered to be On-Line and all other Combined Cycle Generation Resources in the Combined Cycle Train are considered to be Off-Line. Furthermore, until the QSE corrects its COP, the Off-Line Combined Cycle Generation Resources as designated through the application of this process are ineligible for RUC commitment or de-commitment Dispatch Instructions.

(b) For any hour in which QSE-submitted COP entries are used to determine the initial state of a Combined Cycle Generation Resource for a DAM or Day-Ahead Reliability Unit Commitment (DRUC) study and the COP shows multiple Combined Cycle Generation Resources in a Combined Cycle Train to be in an

On-line Resource Status, then until the QSE corrects its COP, the On-Line Combined Cycle Generation Resource that has been On-Line for the longest time from the last recorded start by ERCOT systems, regardless of the reason for the start, combined with the COP Resource Status for the remaining hours of the current Operating Day, is considered to be On-Line at the start of the DRUC study period and all other COP-designated Combined Cycle Generation Resources in the Combined Cycle Train are considered to be Off-Line.

(c) ERCOT systems shall allow only one Combined Cycle Generation Resource in a Combined Cycle Train to offer Off-Line Non-Spin in the DAM or Supplemental Ancillary Services Market (SASM).

[NPRR1007, NPRR1014, and NPRR1029: Replace paragraph (c) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029:]

(c) ERCOT systems shall allow only one Combined Cycle Generation Resource in a Combined Cycle Train to offer Off-Line Non-Spin in the DAM or SCED.

(i) If there are multiple Non-Spin offers from different Combined Cycle Generation Resources in a Combined Cycle Train, then prior to execution of the DAM, ERCOT shall select the Non-Spin offer from the Combined Cycle Generation Resource with the highest HSL for consideration in the DAM and ignore the other offers.

(ii) Combined Cycle Generation Resources offering Off-Line Non-Spin must be able to transition from the shutdown state to the offered Combined Cycle Generation Resource On-Line state and be capable of ramping to the full amount of the Non-Spin offered.

(d) The DAM and RUC shall honor the registered hot, intermediate or cold Startup Costs for each Combined Cycle Generation Resource registered in a Combined Cycle Train when determining the transition costs for a Combined Cycle Generation Resource. In the DAM and RUC, the Startup Cost for a Combined Cycle Generation Resource shall be determined by the positive transition cost from the On-Line Combined Cycle Generation Resource within the Combine Cycle Train or from a shutdown condition, whichever ERCOT determines to be appropriate.

(7) ERCOT may accept COPs only from QSEs.

(8) For the first 168 hours of the COP, ERCOT will update the HSL values for Wind-powered Generation Resources (WGRs) with the most recently updated Short-Term Wind Power Forecast (STWPF), and the HSL values for PhotoVoltaic Generation Resources (PVGRs) with the most recently updated Short-Term PhotoVoltaic Power Forecast (STPPF). ERCOT will notify the QSE via an Extensible Markup Language

(XML) message each time COP HSL values are updated with the forecast values. A QSE representing a WGR may override the STWPF HSL value but must submit an HSL value that is less than or equal to the amount for that Resource from the most recent STWPF provided by ERCOT; a QSE representing a PVGR may override the STPPF HSL value but must submit an HSL value that is less than or equal to the amount for that Resource from the most recent STPPF provided by ERCOT.

[NPRR1029: Replace paragraph (8) above with the following upon system implementation:]

(8) For the first 168 hours of the COP, ERCOT will update the HSL values for Wind-powered Generation Resources (WGRs) with the most recently updated Short-Term Wind Power Forecast (STWPF), and the HSL values for PhotoVoltaic Generation Resources (PVGRs) with the most recently updated Short-Term PhotoVoltaic Power Forecast (STPPF). A QSE representing a DC-Coupled Resource shall provide the capacity value of the Energy Storage System (ESS) that is included in the HSL of the DC-Coupled Resource, and ERCOT will update the DC-Coupled Resource's HSL with the sum of the forecasts of the intermittent renewable generation component and the QSE-submitted value for the ESS component. ERCOT will notify the QSE via an Extensible Markup Language (XML) message each time COP HSL values are updated with the forecast values. A QSE representing a WGR may override the STWPF HSL value but must submit an HSL value that is less than or equal to the amount for that Resource from the most recent STWPF provided by ERCOT; a QSE representing a PVGR may override the STPPF HSL value but must submit an HSL value that is less than or equal to the amount for that Resource from the most recent STPPF provided by ERCOT. A QSE representing a DC-Coupled Resource may override the COP HSL value with a value that is lower than the ERCOT-populated value, and may override with a value that is higher than the ERCOT-populated value if the ESS component of the DC-Coupled Resource can support the higher value.

(9) A QSE representing a Generation Resource that is not actively providing Ancillary Services or is providing Off-Line Non-Spin that the Resource will provide following the shutdown, may only use a Resource Status of SHUTDOWN to indicate to ERCOT through telemetry that the Resource is operating in a shutdown sequence or a Resource Status of ONTEST to indicate in the COP and through telemetry that the Generation Resource is performing a test of its operations either manually dispatched by the QSE or by ERCOT as part of the test. A QSE representing a Generation Resource that is not actively providing Ancillary Services may only use a Resource Status of STARTUP to indicate to ERCOT through telemetry that the Resource is operating in a start-up sequence requiring manual control and is not available for Dispatch.

(10) If a QSE has not submitted a valid COP for any Generation Resource for any hour in the DAM or RUC Study Period, then the Generation Resource is considered to have a Resource Status as OUT thus not available for DAM awards or RUC commitments for those hours.

(11) If a COP is not available for any Resource for any hour from the current hour to the start of the DAM period or RUC study, then the Resource Status for those hours are considered equal to the last known Resource Status from a previous hour's COP or from telemetry as appropriate for that Resource.

(12) A QSE representing a Resource may only use the Resource Status code of EMR for a Resource whose operation would have impacts that cannot be monetized and reflected through the Resource's Energy Offer Curve or recovered through the RUC make-whole process or if the Resource has been contracted by ERCOT under Section 3.14.1 or under paragraph (4) of Section 6.5.1.1. If ERCOT chooses to commit an Off-Line unit with EMR Resource Status that has been contracted by ERCOT under Section 3.14.1 or under paragraph (4) of Section 6.5.1.1, the QSE shall change its Resource Status to ONRUC. Otherwise, the QSE shall change its Resource Status to ONEMR.

(13) A QSE representing a Resource may use the Resource Status code of ONEMR for a Resource that is:

(a) On-Line, but for equipment problems it must be held at its current output level until repair and/or replacement of equipment can be accomplished; or

(b) A hydro unit.

(14) A QSE operating a Resource with a Resource Status code of ONEMR may set the HSL and LSL of the unit to be equal to ensure that SCED does not send Base Points that would move the unit.

(15) A QSE representing a Resource may use the Resource Status code of EMRSWGR only for an SWGR.

[NPRR1026: Insert paragraph (16) below upon system implementation:]

(16) A QSE representing a Self-Limiting Facility must ensure that the sum of the COP HSL/LSL and the sum of the telemetered HSL/LSL submitted for each Resource within the Self-Limiting Facility do not exceed either the limit on MW Injection or the limit on the MW Withdrawal established for the Self-Limiting Facility.

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

(16) A QSE representing a DC-Coupled Resource shall not submit an HSL that exceeds the inverter rating or the sum of the nameplate ratings of the generation component(s) of the Resource.

3.9.2 Current Operating Plan Validation

(1) ERCOT shall verify that each COP, on its submission, complies with the criteria described in Section 3.9.1, Current Operating Plan (COP) Criteria. ERCOT shall notify the QSE by means of the Messaging System if the QSE's COP fails to comply with the criteria described in Section 3.9.1 and this Section 3.9.2 for any reason. The QSE must then resubmit the COP within the appropriate market timeline.

(2) ERCOT may reject a COP that does not meet the criteria described in Section 3.9.1.

(3) If a Resource is designated in the COP to provide Ancillary Service, then ERCOT shall verify that the COP complies with Section 3.16, Standards for Determining Ancillary Service Quantities. The Ancillary Service Supply Responsibilities as indicated in the Ancillary Service Resource Responsibility submitted immediately before the end of the Adjustment Period are physically binding commitments for each QSE for the corresponding Operating Period.

(4) ERCOT shall notify the QSE if the sum of the Ancillary Service capacity designated in the COP for each hour, by service type, is less than the QSE's Ancillary Service Supply Responsibility for each service type for that hour. If the QSE does not correct the deficiency within one hour after receiving the notice from ERCOT, then ERCOT shall follow the procedures outlined in Section 6.4.9.1, Evaluation and Maintenance of Ancillary Service Capacity Sufficiency.

(5) A QSE may change Ancillary Service Resource designations by changing its COP, subject to Section 6.4.9.1.

(6) If ERCOT determines that it needs more Ancillary Service during the Adjustment Period, then the QSE's allocated portion of the additional Ancillary Service may be self-arranged.

[NPRR1007: Delete paragraphs (3)-(6) above upon system implementation of the Real-Time Co-Optimization (RTC) project and renumber accordingly.]

(7) ERCOT systems must be able to detect a change in status of a Resource shown in the COP and must provide notice to ERCOT operators of changes that a QSE makes to its COP.

(8) A QSE representing a Resource that has an Energy Offer Curve valid for an hour of the COP may not designate a Resource Status of ONOS or ONDSR for that hour for that Resource.

[NPRR1000: Replace paragraph (8) above with the following upon system implementation:]

(8) A QSE representing a Resource that has an Energy Offer Curve valid for an hour of the COP may not designate a Resource Status of ONOS for that hour for that Resource.

3.10 Network Operations Modeling and Telemetry

(1) ERCOT shall use the physical characteristics, ratings, and operational limits of all Transmission Elements of the ERCOT Transmission Grid and other information from the Transmission Service Providers (TSPs) and Resource Entities to specify limits within which the transmission network is defined in the network models made available to Market Participants as noted below and used to operate the ERCOT Transmission Grid as updated. If a Private Use Network is not registered as a Resource Entity, then ERCOT shall use equivalent model data provided by TSPs, if available, that represents the Private Use Network in the TSPs' modeling systems for use in the Network Operations Model.

[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 use the physical characteristics, ratings, and operational limits of all Transmission Elements of the ERCOT Transmission Grid and other information from Transmission Service Providers (TSPs), Direct Current Tie Operators (DCTOs), and Resource Entities to specify limits within which the transmission network is defined in the network models made available to Market Participants as noted below and used to operate the ERCOT Transmission Grid as updated. If a Private Use Network is not registered as a Resource Entity, then ERCOT shall use equivalent model data provided by TSPs, if available, that represents the Private Use Network in the TSPs' modeling systems for use in the Network Operations Model.

(2) Because the ERCOT market requires accurate modeling of Transmission Elements in order to send accurate Base Points and pricing signals to Market Participants, ERCOT shall manage the Network Operations Model. By providing Base Points and pricing signals by Electrical Bus to Market Participants, the Market Participants' responses result in power flows on all Transmission Elements that ERCOT must monitor and, if necessary for reliability reasons, manage within ratings provided by the TSP and Resource Entity and limits assigned by ERCOT including Generic Transmission Limits (GTLs) as may be defined in Section 3.10.7.6, Use of Generic Transmission Constraints and Generic Transmission Limits.

[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) Because the ERCOT market requires accurate modeling of Transmission Elements in order to send accurate Base Points and pricing signals to Market Participants, ERCOT shall manage the Network Operations Model. By providing Base Points and pricing signals by Electrical Bus to Market Participants, the Market Participants' responses result in power flows on all Transmission Elements that ERCOT must monitor and, if necessary for reliability reasons, manage within ratings provided by each TSP, DCTO, and Resource Entity and limits assigned by ERCOT including Generic Transmission Limits (GTLs) as may be defined in Section 3.10.7.6, Use of Generic Transmission Constraints and Generic Transmission Limits.

(3) TSPs and Resource Entities shall provide ERCOT with equipment ratings and update the ratings as required by ERCOT. ERCOT may request TSPs and Resource Entities to provide detailed information on the methodology, including data for determination of each requested rating. ERCOT may review and comment on the methodology. ERCOT shall post all methodologies on the Market Information System (MIS) Secure Area within seven days following a change in methodology.

[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 equipment ratings and update the ratings as required by ERCOT. ERCOT may request that a TSP, DCTO, or Resource Entity provide detailed information on the methodology, including data for determination of each requested rating. ERCOT may review and comment on the methodology. ERCOT shall post all methodologies on the Market Information System (MIS) Secure Area within seven days following a change in methodology.

(4) ERCOT must use system ratings consistent with the ratings expected to be used during Real-Time for the system condition being modeled, including Dynamic Ratings using expected temperatures for those system conditions. For each model, ERCOT shall post ratings and the ambient temperatures used to calculate the ratings on the MIS Secure Area when the model is published.

(5) ERCOT shall use consistent information within and between the various models used by ERCOT in a manner that yields consistent results. For operational and planning models that are intended to represent the same system state the results should be consistent and the naming should be identical.

(6) ERCOT shall use a Network Operations Model Change Request (NOMCR) process to control all information entering the Network Operations Model. In order to allow for construction schedules, each NOMCR must be packaged as a single package describing any incremental changes and referencing any prerequisite NOMCRs, using an industry standard data exchange format. A package must contain a series of instructions that define the changes that need to be made to implement a network model change. ERCOT shall verify each package for completeness and accuracy prior to the period it is to be implemented.

(7) ERCOT shall use an automated process to manage the Common Information Model (CIM) compliant packages loaded into the Network Operations Model as each construction phase is completed. ERCOT shall reject any NOMCRs that are not CIM compliant. Each CIM compliant NOMCR must also be associated with commands to update the graphical displays associated with the network model modification. During the testing phase, each NOMCR must be tested for proper sequencing and its effects on downstream applications.

(8) ERCOT shall track each data submittal received from TSPs via the NOMCR process and from Resource Entities via the Resource Registration process. Resource Registration data is converted by ERCOT to the appropriate NOMCR format through implementation and final testing of the change. ERCOT shall notify each TSP and Resource Entity when the requested change is processed and implemented in accordance with Section 3.10.1, Time Line for Network Operations Model Changes. ERCOT shall also provide the submitting TSP a link to a Network Operations Model containing the change for verifying the implementation of the NOMCR and associated one-line displays. ERCOT shall post all NOMCRs on the MIS Certified Area for TSPs only within five Business Days following receipt of the NOMCR, consistent with the requirements regarding ERCOT Critical Energy Infrastructure Information (ECEII) set forth in Section 1.3, Confidentiality. When posting a NOMCR, each change must be posted using the CIM data exchange format showing incremental changes to the last Network Operations Model for TSPs only, to facilitate TSPs in updating their internal network models to reflect changes made at ERCOT. For each NOMCR, ERCOT shall post on the MIS Certified Area for TSPs only the current status on the in-service date for each NOMCR, including any prerequisite NOMCRs provided by the requestor.

[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 shall track each data submittal received from TSPs and DCTOs via the NOMCR process and from Resource Entities via the Resource Registration process. Resource Registration data is converted by ERCOT to the appropriate NOMCR format through implementation and final testing of the change. ERCOT shall notify each TSP, DCTO, and Resource Entity when the requested change is processed and implemented in accordance with Section 3.10.1, Time Line for Network Operations Model Changes. ERCOT shall also provide the submitting TSP and DCTO a link to a Network Operations Model containing the change for verifying the implementation of the NOMCR and associated one-line displays. ERCOT shall post all NOMCRs on the MIS Certified Area for TSPs only within five Business Days following receipt of the NOMCR, consistent with the requirements regarding ERCOT Critical Energy Infrastructure Information (ECEII) set forth in Section 1.3, Confidentiality. When posting a NOMCR, each change must be posted using the CIM data exchange format showing incremental changes to the last Network Operations Model for TSPs only, to facilitate TSPs in updating their internal network models to reflect changes made at ERCOT. For each NOMCR, ERCOT shall post on the MIS Certified Area for TSPs only the current status on the in-service date for each NOMCR, including any prerequisite NOMCRs provided by the requestor.

(9) ERCOT shall update the Network Operations Model under this Section and coordinate it with the planning models for consistency to the extent applicable.

(10) Any requestor of any changes in system topology or telemetry must receive approval from ERCOT before connecting of any associated equipment to the ERCOT Transmission Grid. ERCOT shall notify a requestor of any deficiencies in its submittal for changes in system topology or telemetry. ERCOT shall accept corrections to the submittal if the requestor has corrected any deficiencies by the required submittal date specified in Section 3.10.1. ERCOT shall post any changes to an NOMCR on the MIS Certified Area for TSPs within three Business Days of accepting corrections.

[NPRR857: Replace paragraph (10) 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:]

(10) Any requestor of any changes in system topology or telemetry must receive approval from ERCOT before connecting of any associated equipment to the ERCOT Transmission Grid. ERCOT shall notify a requestor of any deficiencies in its submittal for changes in system topology or telemetry. ERCOT shall accept corrections to the submittal if the requestor has corrected any deficiencies by the required submittal date

specified in Section 3.10.1. ERCOT shall post any changes to a NOMCR on the MIS Certified Area for TSPs and DCTOs within three Business Days of accepting corrections.

(11) On receipt of the information set forth in Section 3.10.7, ERCOT System Modeling Requirements, ERCOT shall review the information and notify the requestor of any required modifications. ERCOT may, at its discretion, require changes or more details regarding the work plan for any new or relocated facilities. The requestor shall notify ERCOT and any other affected Entities as soon as practicable of any ERCOT requested changes to the work plan. The requestor shall consult with other Entities likely to be affected and shall revise the work plan, following any necessary or appropriate discussions with ERCOT and other affected Entities. ERCOT shall approve or reject the request, including any revisions made by the requestor, within 15 days of receipt of the complete request and any revisions. Following ERCOT approval, ERCOT shall publish a summary of the revised NOMCR on the MIS Certified Area for TSPs.

[NPRR857: Replace paragraph (11) 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:]

(11) On receipt of the information set forth in Section 3.10.7, ERCOT System Modeling Requirements, ERCOT shall review the information and notify the requestor of any required modifications. ERCOT may, at its discretion, require changes or more details regarding the work plan for any new or relocated facilities. The requestor shall notify ERCOT and any other affected Entities as soon as practicable of any ERCOT requested changes to the work plan. The requestor shall consult with other Entities likely to be affected and shall revise the work plan, following any necessary or appropriate discussions with ERCOT and other affected Entities. ERCOT shall approve or reject the request, including any revisions made by the requestor, within 15 days of receipt of the complete request and any revisions. Following ERCOT approval, ERCOT shall publish a summary of the revised NOMCR on the MIS Certified Area for TSPs and DCTOs.

3.10.1 Time Line for Network Operations Model Changes

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

[NPRR857: Replace paragraph (1) above with the following upon system implementation 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 perform periodic updates to the Network Operations Model. Market Participants may provide Network Operations Model updates to ERCOT to implement planned transmission and Resource construction one year before the required submittal date below. TSPs, DCTOs, and Resource Entities must timely submit Network Operations Model changes pursuant to the schedule in this Section to be included in the updates.

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

[NPRR995: Replace paragraph (2) above with the following upon system implementation:]

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

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

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

Notes:

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

[NPRR857: Replace paragraph (3) above with the following upon system implementation 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) TSPs, DCTOs, and Resource Entities shall submit Network Operations Model updates at least three months prior to the physical equipment change. ERCOT shall update the Network Operations Model according to the following table:

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

Notes:

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

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