**ERCOT Nodal Protocols**

**Section 3: Management Activities for the ERCOT System**

**September 1, 2018**

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# MANAGEMENT ACTIVITIES FOR THE ERCOT SYSTEM

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

3.1 Outage Coordination

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

3.1.1 Role of ERCOT

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

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

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

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

(c) Coordinating and approving or rejecting schedules for Planned Outages of Resources scheduled to occur within 45 days after request;

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

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

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

(g) Reviewing and coordinating changes to existing 12-month Resource Outage plans to determine how changes will affect ERCOT System reliability, including Resource Outages not previously included in the Outage plan;

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

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

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

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

(l) Establishing and implementing communication procedures:

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

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

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

(n) Planning and analyzing Transmission Facilities Outages.

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

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

3.1.3 Rolling 12-Month Outage Planning and Update

**3.1.3.1 Transmission Facilities**

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

**3.1.3.2 Resources**

(1) Each Resource Entity shall provide to ERCOT a Planned Outage and Maintenance Outage plan for Generation Resources in an ERCOT-provided format for the next 12 months updated monthly. Planned Outage and Maintenance Outage scheduling data must be kept current. Updates, through an electronic interface as specified by ERCOT, must identify any changes to previously proposed Planned Outages or Maintenance Outages and any additional Planned Outages or Maintenance Outages anticipated over the next 12 months.

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

3.1.4 Communications Regarding Resource and Transmission Facilities Outages

**3.1.4.1 Single Point of Contact**

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

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

**3.1.4.2 Method of Communication**

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

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

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

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

**3.1.4.4 Management of Resource or Transmission Forced Outages or Maintenance Outages**

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

(a) For Resource Outages:

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

(ii) Updating the COP; and

(iii) Updating the Outage Scheduler, if necessary.

(b) For Transmission Facilities Forced Outages:

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

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

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

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

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

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

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

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

(2) Any Forced Outage that occurs in Real-Time must be entered into the Outage Scheduler if it is to remain an Outage for longer than two hours.

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

**3.1.4.6 Outage Coordination of Forecasted Emergency Conditions**

(1) If ERCOT forecasts an inability to meet applicable reliability standards and it has exercised all other reasonable options, ERCOT shall inform the Single Point of Contact for any affected Market Participant and all QSEs verbally and in electronic form by declaring an Emergency Condition according to Section 6.5.9.3, Communication under Emergency Conditions.

(2) Under an Emergency Condition and if ERCOT cannot meet applicable reliability standards, ERCOT may discuss the reliability problem with Resource Entities, TSPs, and Distribution Service Providers (DSPs) to reach mutually agreeable solutions where Outages are negatively affecting system reliability. Actions may include changes to Outage schedules and the COP.

**3.1.4.7 Reporting of Forced Derates**

(1) The Resource Entity or its designee must enter Forced Derates that are expected to last more than 48 hours into the Outage Scheduler.

3.1.5 Transmission System Outages

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

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

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

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

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

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

**3.1.5.2 Receipt of TSP Requests by ERCOT**

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

**3.1.5.3 Timelines for Response by ERCOT for TSP Requests**

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

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

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

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

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

**3.1.5.4 Delay**

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

**3.1.5.5 Opportunity Outage of Transmission Facilities**

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

**3.1.5.6 Rejection Notice**

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

(a) Specific concerns causing the rejection;

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

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

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

(a) To protect system reliability or security;

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

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

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

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

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

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

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

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

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

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

**3.1.5.8 Priority of Approved Planned, Maintenance, and Rescheduled Outages**

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

**3.1.5.9 Information for Inclusion in Transmission Facilities Outage Requests**

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

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

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

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

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

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

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

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

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

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

**3.1.5.10 Additional Information Requests**

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

**3.1.5.11 Evaluation of Transmission Facilities Planned Outage or Maintenance Outage Requests**

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

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

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

(c) Forced Outages of Transmission Facilities;

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

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

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

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

(h) Good Utility Practice for Transmission Facilities maintenance.

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

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

**3.1.5.12 Submittal Timeline for Transmission Facility Outage Requests**



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

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

Note:

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

**3.1.5.13 Transmission Report**

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

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

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

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

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

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

3.1.6 Outages of Resources Other than Reliability Resources

(1) ERCOT shall accept all Outage schedules and changes to Outage schedules for a Resource other than a reliability Resource submitted to ERCOT more than 45 days before the proposed start date of the Outage.

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

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

(b) ERCOT shall approve Planned Outage proposals, except that ERCOT shall reject an Outage proposal if it will impair ERCOT’s ability to meet applicable reliability standards and other solutions cannot be exercised.

(c) ERCOT shall accept Forced and Maintenance Outage plans from a Qualifying Facility (QF) that result from the outage of the QF’s thermal host facility.

**3.1.6.1 Receipt of Resource Requests by ERCOT**

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

**3.1.6.2 Resources Outage Plan**

(1) Resource Entity Outage requests shall include the following information:

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

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

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

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

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

(f) The nature of work to be performed during the Outage.

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

**3.1.6.3 Additional Information Requests**

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

**3.1.6.4 Approval of Changes to a Resource Outage Plan**

(1) ERCOT shall accept all changes to a Resource Outage plan submitted by a Resource Entity more than 45 days before the planned start date for the Outage. Following acceptance, where ERCOT determines that Outage requests are expected to result in a violation of an ERCOT reliability criterion or that may result in a cancellation of a Transmission Facilities Planned Outage, ERCOT may discuss such concerns with Resource Entities or QSEs in an attempt to reach a mutually agreeable resolution, including rescheduling the Outage in a manner agreeable to the Resource Entity.

(2) A Resource Entity must request approval from ERCOT only for new Resource Outages or changes to a previously accepted planned Resource Outage scheduled to occur within 45 days of the request.

(3) ERCOT shall approve Planned Outage and Maintenance Outage requests to occur within 45 days, except that ERCOT shall reject proposals if the Outage proposal will impair ERCOT’s ability to meet applicable reliability standards.

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

**3.1.6.5 Evaluation of Proposed Resource Outage**

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

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

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

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

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

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

**3.1.6.6 Timelines for Response by ERCOT for Resource Outages**

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

|  |  |
| --- | --- |
| Amount of time between a request for acceptance of a Planned Outage and the scheduled start of the proposed Outage: | ERCOT shall approve, accept or reject no later than: |
| Three days | ERCOT shall approve or reject within 1800 hours, two days before the start of the proposed Outage |
| Between four and eight days | ERCOT shall approve or reject within 1800 hours, three days prior to the start of the proposed Outage |
| Between nine and 45 days | Five Business Days after submission. Planned Outages are automatically accepted if not rejected at the end of the fifth Business Day following receipt of request. |
| Greater than 45 days | ERCOT must accept, but ERCOT may discuss reliability and scheduling impacts to minimize cost to the ERCOT System in an attempt to accomplish minimum overall impact. Within five Business Days, ERCOT will notify the submitter if there is a conflict with a previously scheduled Outage. |

(2) If circumstances prevent adherence to these timetables, ERCOT shall discuss the request status and reason for the delay of decision with the QSE and make reasonable attempts to mitigate the effect of the delay.

**3.1.6.7 Delay**

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

**3.1.6.8 Resource Outage Rejection Notice**

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

(a) Specific reasons causing the rejection; or

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

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

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

(b) Due to insufficient information regarding the Outage;

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

(d) As specified elsewhere in these Protocols.

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

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

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

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

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

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

**3.1.6.10 Opportunity Outage**

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

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

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

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

**3.1.6.11 Outage Returning Early**

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

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

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

(2) Before an early return from an Outage, a Resource Entity or QSE may inquire of ERCOT whether the Resource is expected to be decommitted by ERCOT upon its early return. If a Resource Entity or QSE is notified by ERCOT that the Resource will be decommitted if it returns early and the Resource Entity or QSE starts the Resource within the previously accepted or approved Outage period, then the QSE representing the Resource will not be paid any decommitment compensation as otherwise would be provided for in Section 5.7, Settlement for RUC Process.

**3.1.6.12 Resource Coming On-Line**

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

3.1.7 Reliability Resource Outages

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

(a) Load forecast;

(b) All other known Outages; and

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

**3.1.7.1 Timelines for Response by ERCOT on Reliability Resource Outages**

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

|  |  |
| --- | --- |
| Amount of time between a Request for approval of a proposed Planned Outage and the scheduled start date of the proposed Outage: | ERCOT shall approve or reject no later than: |
| No less than 30 days | 15 days before the start of the proposed Outage |
| Greater than 45 days | 30 days before the start of the proposed Outage |

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

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

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

**3.1.7.2 Changes to an Approved Reliability Resource Outage Plan**

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

3.1.8 High Impact Transmission Element (HITE) Identification

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

3.2 Analysis of Resource Adequacy

3.2.1 Calculation of Aggregate Resource Capacity

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

(2) Monthly, ERCOT shall calculate the aggregate weekly Generation Resource capacity for the ERCOT Region and the Forecast Zones projected to be available during the ERCOT Region peak Load hour of each week for the following 36 months, starting with the second week and the aggregate weekly Load Resource capacity for the ERCOT Region projected to be available during the ERCOT Region peak Load hour of each week for the following 36 months, starting with the second week.

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

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

(5) ERCOT shall publish procedures describing the IRR forecasting process on the Market Information System (MIS) Public Area.

3.2.2 Demand Forecasts

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

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

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

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

(5) ERCOT shall publish procedures describing the forecasting process on the MIS Public Area.

3.2.3 System Adequacy Reports

(1) ERCOT shall publish system adequacy reports to assess the adequacy of Resources and Transmission Facilities to meet the projected Demand. ERCOT shall provide reports on a system-wide basis and by Forecast Zone, where applicable.

(2) ERCOT shall generate and post a “Medium-Term System Adequacy Report” on the MIS Secure Area. ERCOT shall update the report monthly using the latest aggregate Generation Resource capacity and Load Resource capacity. The data will be provided for each week, starting with the second week, of a rolling 36-month period. The Medium-Term System Adequacy Report will provide:

(a) Generation Resource capacity at the time of forecasted weekly peak Demand;

(b) Load Resource capacity at the time of the forecasted weekly peak Demand;

(c) Weekly peak forecast Demand described in Section 3.2.2, Demand Forecasts;

(d) Calculated system reserve, highlighting any deficiency hours, that excludes Load Resource capacity;

(e) Calculated system reserve, highlighting any deficiency hours, that includes Load Resource capacity shown as a reduction in forecast Demand;

(f) Ancillary Service requirements; and

(g) Transmission constraints that have a high probability of being binding in the Security-Constrained Economic Dispatch (SCED) or Day-Ahead Market (DAM) given the forecasted system conditions for each week excluding the effects of any transmission or Resource Outages.

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

(a) For Generation Resources, the available On-Line Resource capacity for each hour, using the COP for the first seven days;

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| ***[NPRR843: Replace paragraph (a) above with the following upon system implementation:]***  (a) For Generation Resources, the available On-Line Resource capacity for each hour, using the COP for the first seven days and considering Resources with a COP Resource Status listed in paragraph (5)(b)(i) of Section 3.9.1, Current Operating Plan (COP) Criteria; |

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

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

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

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

(c) For Load Resources, the available capacity for each hour using the COP;

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| ***[NPRR843: Replace paragraph (c) above with the following upon system implementation:]***  (c) For Load Resources, the available capacity for each hour using the COP for the first seven days and considering Resources with a COP Resource Status of ONRGL, ONCLR, or ONRL; |

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

(e) Ancillary Service requirements for the Operating Day and subsequent days, updated daily;

(f) Transmission constraints that have a high probability of being binding in SCED or DAM given the forecasted system conditions for each week including the effects of any transmission or Resource Outages. The binding constraints may not be updated every hour; and

(g) For Generation Resources, the available Off-Line Resource capacity that can be started for each hour, using the COP for the first seven days.

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| ***[NPRR843: Replace paragraph (g) above with the following upon system implementation:]***  (g) For Generation Resources, the available Off-Line Resource capacity that can be started for each hour, using the COP for the first seven days and considering Resources with a COP Resource Status of OFF or OFFNS and temporal constraints. |

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| ***[NPRR864: Insert paragraph (h) below upon system implementation:]***  (h) Following each Hourly Reliability Unit Commitment (HRUC), the available On-Line capacity from Generation Resources, based on Real-Time telemetry, for which the COP Resource Status is OFF, OUT, or EMR for all hours within the HRUC Study Period. The available On-Line capacity will consider those Resources with a Real-Time Resource Status listed in paragraph (5)(b)(i) of Section 3.9.1, Current Operating Plan (COP) Criteria, excluding SHUTDOWN. |

3.2.4 Reporting of Statement of Opportunities

(1) In accordance with P.U.C. Subst. R. 25.505, Resource Adequacy in the Electric Reliability Council of Texas Power Region, ERCOT shall publish on the MIS Public Area a “Statement of Opportunities” that provides a projection of the capability of existing and planned Generation Resources, Load Resources, and Transmission Facilities to reliably meet ERCOT’s projected needs.

3.2.5 Publication of Resource and Load Information

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

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

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

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

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

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

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

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

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

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

(b) The actual ERCOT Load as determined by subtracting the Direct Current Tie (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 MIS Public Area 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, 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) Service, ERCOT shall separately post aggregated offers from Generation Resources, Controllable Load Resources, and non-Controllable Load Resources. 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;

(g) The aggregate amount of cleared Ancillary Service Offers; 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 MIS Public Area the following information for each Resource for each 15-minute Settlement Interval 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;

(b) The Generation Resource name and the Generation Resource’s Output Schedule;

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

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

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

(f) 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; and

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

(g) 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 Maximum Power Consumption (MPC for a Load Resource);

(iv) The Low Power Consumption (LPC for a Load Resource);

(v) The telemetered real power consumption; and

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

(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 MIS Public Area 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.

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| ***[NPRR843: Insert paragraph (6) below upon system implementation and renumber accordingly:]***  (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 MIS Public Area 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. |

(6) ERCOT shall post on the MIS Public Area the offer price and the name of the Entity submitting the offer for the highest-priced offer selected or Dispatched by SCED 48 hours after the end of the applicable Operating Day. If multiple Entities submitted the highest-priced offers selected, all Entities shall be identified on the MIS Public Area.

(7) ERCOT shall post on the MIS Public Area the bid price and the name of the Entity submitting the bid for the highest-priced bid selected or Dispatched by SCED 48 hours after the end of the applicable Operating Day. If multiple Entities submitted the highest-priced bids selected, all Entities shall be identified on the MIS Public Area.

(8) ERCOT shall post on the MIS Public Area the offer price and the name of the Entity submitting the offer for the highest-priced Ancillary Service Offer selected for each Ancillary Service 48 hours after the end of the applicable Operating Day. If multiple Entities submitted the highest-priced offers selected, all Entities shall be identified on the MIS Public Area.

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| ***[NPRR843: Replace paragraph (8) above with the following upon system implementation:]***  (8) ERCOT shall post on the MIS Public Area 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 48 hours 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 MIS Public Area. The report shall specify whether the Ancillary Service Offer was selected in a DAM or a SASM. |

(9) ERCOT shall post on the MIS Public Area for each Operating Day the following information for each Resource:

(a) The Resource name;

(b) The names of the Entities providing information to ERCOT;

(c) The names of the Entities controlling each Resource. ERCOT shall determine whether the Entity is in control of each Resource in accordance with subsection (e) of P.U.C. Subst. R. 25.502, Pricing Safeguards in Markets Operated by the Electric Reliability Council of Texas; and

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

(10) ERCOT shall post on the MIS Public Area 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;

(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.

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| ***[NPRR843: Insert paragraph (11) below upon system implementation:]***  (11) ERCOT shall post on the MIS Public Area 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. |

**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, the 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. The report shall include the total NOIE’s unregistered DG MW capacity above 50 kW by Load Zone and by primary fuel type as follows:

(a) Solar;

(b) Wind;

(c) Other renewable; and

(d) Other non-renewable.

**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 MIS Public Area. 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:

**PRM** *s, i* **= (TOTCAP** s, *i* **– FIRMPKLD** s, *i***) / 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:

**FIRMPKLD *s, i* = TOTPKLD s, *i* – LRRRS *s, i* –LRNSRS­ *s, i* – ERS *s, i* – CLR *s, i* – 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*. |
| LRNSRS *s, i* | MW | *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.* |
| ERS *s, i* | MW | *Emergency Response Service (ERS)*—The estimated amount of ERS for the Peak Load Season *s* for the year *i* calculated as follows:   |  |  |  | | --- | --- | --- | | **Year (i)** | **Winter Peak Load** | **Summer Peak Load** | | Current Year (i = 1) | The simple average of the amount of ERS procured by ERCOT for the current year Standard Contract Term of October 1 to January 31 for the ERS Time Periods covering all or any part of Hour Ending 0600 and Hour Ending 1800. | 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. | | Second Year (i = 2) | 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. | 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. | | Third Year (i = 3) | 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. | 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. | | Years after Third Year (i > 3) | Equal to third year amount. | Equal to third year amount. | |
| CLR *s, i* | MW | *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). |
| 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 Non-Opt-In Entities (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:

**TOTCAP *s ,i* = INSTCAP *s*, *i +* PUNCAP *s, i +* WINDCAP *s, i, r*  + HYDROCAP *s, i* + SOLARCAP*s,*** ***i* + RMRCAP *s,*** ***i* + DCTIECAP *s, i* + SWITCHCAP *s, i* + MOTHCAP *s, i* + PLANNON *s, i* + PLANIRR *s, i, r* – UNSWITCH *s, i* – RETCAP *s, i***

The above variables are defined as follows:

| Variable | Unit | Definition |
| --- | --- | --- |
| TOTCAP *s, i* | MW | *Total Capacity*—Estimated total capacity available during the Peak Load Season *s* for the year *i.* |
| 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. |
| PUNCAP *s, i* | MW | *Private Use Network Capacity*—The forecasted generation capacity available to the ERCOT Transmission Grid, net of self-serve load, from All-Inclusive Generation Resources 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 All-Inclusive Generation Resources 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. |
| WINDPEAKPCT *s, r* | % | *Seasonal Peak Average Wind Capacity as a Percent of Installed Capacity*—The average wind 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 average of the previous ten eligible years of Seasonal Peak Average values. 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. |
| SOLARCAP*s, i* | MW | *Solar Unit Capacity*—The average PVGR 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 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. |
| 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. |
| DCTIECAP *s, i* | MW | *Seasonal Net Max Sustainable Rating for DC Tie Resource*—The average DC Tie capacity imported into the ERCOT Region 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 DC Tie Resources (1) that have been energized no later than the start of the most current Peak Load Season used for the calculation, and (2) that have not been permanently removed from service by the start of the most current Peak Load Season used for the calculation. |
| 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 asset 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. |
| PLANNON *s, i* | MW | *New, non-IRR Generating Capacity*—The amount of new, non-IRR generating capacity for the Peak Load Season *s* 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 Interconnect 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. Exclude new, non-IRR generating capacity that has met the requirements of (a), (b), (c) and (d) above for which ERCOT has received written Notification from the developer that the new capacity will not be constructed. |
| PLANIRR *s, i, r* | MW | *New IRR Capacity*—For new WGRs, the capacity available for the summer and winter Peak Load Seasons *s,* year *i*, and region *r*, multiplied by WINDPEAKPCT for summer and winter Load Season *s* and region *r*. For new solar units, 100% of the nameplate capacity units until a threshold value of 200 MWs of registered wholesale installed solar capacity is reached for summer Peak Load Season *s* and year *i*. Once the 200 MW threshold value is reached, the average solar unit capacity available, as determined from the COP, during the highest 20 peak Load hours for each preceding three-year period for summer Peak Load Season *s* and year *i.* 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. |
| 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 a Notification of Suspension of Operations (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, that has not otherwise been considered in any of the above defined categories. For All-Inclusive Generation Resources within Private Use Networks, the retired capacity amount is the peak average capacity contribution included in PUNCAP. For reporting of individual All-Inclusive Generation Resources 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. |
| *i* | None | Year. |
| *s* | None | Summer and winter Peak Load Seasons for year *i*. |
| *r* | None | Coastal and non-coastal wind regions. WGRs are classified into regions based on the county that contains their Point of Interconnection (POI). The coastal region is defined as the following counties: Cameron, Willacy, Kenedy, Kleberg, Nueces, San Patricio, Refugio, Aransas, Calhoun, Matagorda, and Brazoria. The non-coastal 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.

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:

(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.

(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.

**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) 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 (2) below.

(2) 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; 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 Market Information System (MIS) Public Area. 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.

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 |
| 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 | WEBB | 345 | NORTH |
| 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:

**DASPP** *North345* **= DASL – (DAHUBSF***North345, c***\* DASP** *c***),**

**if HBBC***North345***≠0**

**DASPP** *North345* **= DASPP** *ERCOT345Bus***, if HBBC***North345***=0**

Where:

DAHUBSF *North345, c =* (HUBDF *hb, North345, c* \* DAHBSF *hb, North345, c*)

DAHBSF *hb, North345, c =* (HBDF *pb, hb, North345, c* \* DASF *pb, hb, North345, c*)

HUBDF *hb, North345, c =* IF(HB*North345, c*=0, 0, 1 **/** HB *North345, c*)

HBDF *pb, hb, North345, c =* IF(PB*hb, North345, c*=0, 0, 1 **/** PB *hb, North345, c*)

The above variables are defined as follows:

| Variable | Unit | Definition |
| --- | --- | --- |
| 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. |
| 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. |
| 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. |
| 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. |
| 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. |
| 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*. |
| 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*. |
| 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. |
| 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:

RTSPP *North345* = Max [-$251, (RTRSVPOR + RTRDP +

(HUBDF *hb, North345* \* ((RTHBP *hb, North345, y* \*

TLMP *y*) / (TLMP *y*))))], if HB*North345*≠0

RTSPP *North345* = RTSPP *ERCOT345Bus*, if HB*North345*=0

Where:

RTRSVPOR = (RNWF *y* \* RTORPA *y*)

RTRDP = (RNWF *y* \* RTORDPA *y*)

RNWF *y* = TLMP *y* / TLMP *y*

RTHBP *hb, North345, y* = (HBDF *b, hb, North345* \* RTLMP *b, hb, North345, y*)

HUBDF *hb, North345* = IF(HB*North345*=0, 0, 1 **/** HB *North345*)

HBDF *b, hb, North345* = IF(B*hb, North345*=0, 0, 1 **/** B *hb, North345*)

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. |
| 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. |
| 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 |
| HUBDF *hb, North345* | none | *Hub Distribution Factor per Hub Bus*⎯The distribution factor of Hub Bus *hb*. |
| 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. |
| 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. |
| HB*North345* | none | The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus. |

**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 |
| 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:

**DASPP** *South345* **= DASL – (DAHUBSF***South345, c***\* DASP** *c***),**

**if HBBC***South345***≠0**

**DASPP** *South345* **= DASPP** *ERCOT345Bus***, if HBBC***South345***=0**

Where:

DAHUBSF *South345, c =* (HUBDF *hb, South345, c* \* DAHBSF *hb, South345, c*)

DAHBSF *hb, South345, c =* (HBDF *pb, hb, South345, c* \* DASF *pb, hb, South345, c*)

HUBDF *hb, South345, c =* IF(HB*South345, c*=0, 0, 1 **/** HB *South345, c*)

HBDF *pb, hb, South345, c =* IF(PB*hb, South345, c*=0, 0, 1 **/** PB *hb, South345, c*)

The above variables are defined as follows:

| Variable | Unit | Definition |
| --- | --- | --- |
| 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. |
| 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. |
| 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. |
| 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. |
| 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. |
| 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*. |
| 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*. |
| 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. |
| 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:

RTSPP *South345* = Max [-$251, (RTRSVPOR + RTRDP +

(HUBDF *hb, South345* \* ((RTHBP *hb, South345, y* \* TLMP *y*) / (TLMP *y*))))], if HB*South345*≠0

RTSPP *South345* = RTSPP *ERCOT345Bus*, if HB*South345*=0

Where:

RTRSVPOR = (RNWF  *y* \* RTORPA *y*)

RTRDP = ( RNWF*y* \* RTORDPA*y*)

RNWF *y* = TLMP *y* / TLMP *y*

RTHBP *hb, South345, y* = (HBDF *b, hb, South345* \* RTLMP *b, hb, South345, y*)

HUBDF *hb, South345* = IF(HB*South345*=0, 0, 1 **/** HB*South345*)

HBDF *b, hb, South345* = IF(B*hb, South345*=0, 0, 1 **/** B *hb, South345*)

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. |
| 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. |
| 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. |

**3.5.2.3 Houston 345 kV Hub (Houston 345)**

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

|  | ERCOT Operations | |  |
| --- | --- | --- | --- |
| No. | 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:

**DASPP** *Houston345* **= DASL – (DAHUBSF***Houston345, c***\* DASP** *c***),**

**if HBBC***Houston345***≠0**

**DASPP** *Houston345* **= DASPP** *ERCOT345Bus***, if HBBC***Houston345***=0**

Where:

DAHUBSF *Houston345, c =* (HUBDF *hb, Houston345, c* \* DAHBSF *hb, Houston345, c*)

DAHBSF *hb, Houston345, c =* (HBDF *pb, hb, Houston345, c* \* DASF *pb, hb, Houston345, c*)

HUBDF *hb, Houston345, c =* IF(HB*Houston345, c*=0, 0, 1 **/** HB *Houston345, c*)

HBDF *pb, hb, Houston345, c =* IF(PB*hb, Houston345, c*=0, 0, 1 **/** 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 *Houston345* = Max [-$251, (RTRSVPOR + RTRDP +

(HUBDF *hb, Houston345* \* ((RTHBP *hb, Houston345, y* \*

TLMP *y*) / (TLMP *y*))))], if HB*Houston345*≠0

RTSPP *Houston345* = RTSPP *ERCOT345Bus*, if HB*Houston345*=0

Where:

RTRSVPOR = (RNWF *y* \* RTORPA *y*)

RTRDP = (RNWF *y* \* RTORDPA *y*)

RNWF *y* = TLMP *y* / TLMP *y*

RTHBP *hb, Houston345, y* = (HBDF *b, hb, Houston345* \* RTLMP *b, hb, Houston345, y*)

HUBDF *hb, Houston345* = IF(HB*Houston345*=0, 0, 1 **/** HB*Houston345*)

HBDF *b, hb, Houston345* = IF(B*hb, Houston345*=0, 0, 1 **/** B *hb, Houston345*)

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. |
| RTHBP *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. |
| RTLMP *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*. |
| 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. |

**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 | ABMB | 345 | WEST |
| 2 | BOMSW | 345 | WEST |
| 3 | OECCS | 345 | WEST |
| 4 | BTRCK | 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 | SARC | 345 | WEST |
| 16 | SWESW | 345 | WEST |
| 17 | TWINBUTE | 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:

**DASPP** *West345* **= DASL – (DAHUBSF***West345, c***\* DASP** *c***),**

**if HBBC***West345***≠0**

**DASPP** *West345* **= DASPP** *ERCOT345Bus***, if HBBC***West345***=0**

Where:

DAHUBSF *West345, c =* (HUBDF *hb, West345, c* \* DAHBSF *hb, West345, c*)

DAHBSF *hb, West345, c =* (HBDF *pb, hb, West345, c* \* DASF *pb, hb, West345, c*)

HUBDF *hb, West345, c =* IF(HB*West345, c*=0, 0, 1 **/** HB *West345, c*)

HBDF *pb, hb, West345, c =* IF(PB*hb, West345, c*=0, 0, 1 **/** 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:

RTSPP *West345* = Max [-$251, (RTRSVPOR + RTRDP +

(HUBDF *hb, West345* \* ((RTHBP *hb, West345, y* \* TLMP *y*) / (TLMP *y*))))], if HB*West345*≠0

RTSPP *West345* = RTSPP *ERCOT345Bus*, if HB*West345*=0

Where:

RTRSVPOR = (RNWF *y* \* RTORPA *y*)

RTRDP = (RNWF *y* \* RTORDPA *y*)

RNWF *y* = TLMP *y* / TLMP *y*

RTHBP *hb, West345, y* = (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*. |
| 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. |

|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| ***[NPRR817: Insert Section 3.5.2.5 below upon system implementation and renumber accordingly:]***  **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:  **DASPP** *Pan345* **=**  **DASL – (DAHUBSF***Pan345, c***\* DASP** *c***),**  **if HBBC***Pan345***≠0**  **DASPP** *Pan345* **=**  **DASPP** *ERCOT345Bus***, if HBBC***Pan345***=0**  Where:  DAHUBSF *Pan345, c =* (HUBDF *hb, Pan345, c* \* DAHBSF *hb, Pan345, c*)  DAHBSF *hb, Pan345, c =* (HBDF *pb, hb, Pan345, c* \* DASF *pb, hb, Pan345, c*)  HUBDF *hb, Pan345, c =* IF(HB*Pan345, c*=0, 0, 1 **/** HB *Pan345, c*)  HBDF *pb, hb, Pan345, c =* IF(PB*hb, Pan345, c*=0, 0, 1 **/** PB *hb, Pan345, c*)  The above variables are defined as follows:   | Variable | Unit | Definition | | --- | --- | --- | | 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. | | DASP *c* | $/MWh | *Day-Ahead Shadow Price for a binding transmission constraint*⎯The DAM Shadow Price for the constraint *c* for the hour. | | 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. | | 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. | | 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. | | 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. | | 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*. | | 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*. | | 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. | | 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:  **RTSPP** *Pan345* **= Max [-$251, (RTRSVPOR + RTRDP +**  **(HUBDF** *hb, Pan345* **\* (****(RTHBP** *hb, Pan345, y* **\* TLMP** *y***) / (** **TLMP** *y***))))], if HB***Pan345***≠0**  **RTSPP** *Pan345* **= RTSPP** *ERCOT345Bus*, **if HB***Pan345***=0**  Where:  RTRSVPOR =  (RNWF *y* \* RTORPA *y*)  RTRDP =  (RNWF *y* \* RTORDPA *y*)  RNWF *y* = TLMP *y* / TLMP *y*  RTHBP *hb, Pan345, y* =  (HBDF *b, hb, Pan345* \* RTLMP *b, hb, Pan345, y*)  HUBDF *hb, Pan345* = IF(HB *Pan345*=0, 0, 1 **/** HB*Pan345*)  HBDF *b, hb, Pan345* = IF(B*hb, Pan345*=0, 0, 1 **/** B *hb, Pan345*)  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. | | 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, 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*. | | 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*. | | 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, 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. | |

**3.5.2.5 ERCOT Hub Average 345 kV Hub (ERCOT 345)**

(1) The ERCOT Hub Average 345 kV Hub price, for both Day-Ahead and 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.

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| ***[NPRR817: Replace paragraph (1) above with the following upon system implementation:]***  (1) The ERCOT Hub Average 345 kV Hub price, for both Day-Ahead and 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 the 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:

DASPP *ERCOT345* = (DASPP *North345* + DASPP *South345* + DASPP *Houston345* + DASPP *West345*) / 4

The above variables are defined as follows:

|  |  |  |
| --- | --- | --- |
| Variable | Unit | Definition |
| DASPP *ERCOT345* | $/MWh | *Day-Ahead Settlement Point Price at ERCOT 345*⎯The DAM Settlement Point Price at ERCOT 345 Hub for the hour. |
| DASPP *North345* | $/MWh | *Day-Ahead Settlement Point Price at North 345*⎯The DAM Settlement Point Price at the North345 Hub for the hour. |
| DASPP *South345* | $/MWh | *Day-Ahead Settlement Point Price at South 345*⎯The DAM Settlement Point Price at the South 345 Hub for the hour. |
| DASPP *Houston345* | $/MWh | *Day-Ahead Settlement Point Price at Houston 345*⎯The DAM Settlement Point Price at the Houston 345 Hub for the hour. |
| DASPP *West345* | $/MWh | *Day-Ahead Settlement Point Price at West 345*⎯The DAM Settlement Point Price at the West 345 Hub for the hour. |

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

RTSPP *ERCOT345* = (RTSPP *North345* + RTSPP *South345* + RTSPP *Houston345* + 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-TimeSettlement 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 North345 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. |

**3.5.2.6 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).

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| ***[NPRR817: Replace paragraph (1) above with the following 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 is 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:

**DASPP** *ERCOT345Bus* **= DASL – (DAHUBSF***ERCOT345Bus, c***\* DASP** *c***),**

**if HBBC***ERCOT345Bus***≠0**

**DASPP** *ERCOT345Bus* **= 0, if HBBC***ERCOT345Bus***=0**

Where:

DAHUBSF *ERCOT345Bus, c =* (HUBDF *hb, ERCOT345Bus, c* \* DAHBSF *hb, ERCOT345Bus, c*)

DAHBSF *hb, ERCOT345Bus, c  =* (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 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:

RTSPP *ERCOT345Bus* = Max [-$251, (RTRSVPOR + RTRDP +

(HUBDF *hb, ERCOT345Bus* \* ((RTHBP *hb, ERCOT345Bus, y* \* TLMP *y*) / (TLMP *y*))))], if HB *ERCOT345Bus* ≠0

RTSPP *ERCOT345Bus* = 0, if HB*ERCOT345Bus* =0

Where:

RTRSVPOR = (RNWF *y* \* RTORPA *y*)

RTRDP = (RNWF *y* \* RTORDPA *y*)

RNWF *y* = TLMP *y* / TLMP *y*

RTHBP *hb, ERCOT345Bus, y* = (HBDF *b, hb, ERCOT345Bus* \* RTLMP *b, hb, ERCOT345Bus, y*)

HUBDF *hb, ERCOT345Bus* = 1 **/** (HB*North345* + HB*South345* + HB*Houston345* + HB*West345*)

If Electrical Bus *b* is a component of “North 345”

HBDF *b, hb, ERCOT345Bus* = IF(B *hb, North345*=0, 0, 1 **/** B *hb, North345*)

Otherwise

If Electrical Bus *b* is a component of “South 345”

HBDF *b, hb, ERCOT345Bus* = IF(B *hb, South345*=0, 0, 1 **/** B *hb, South345*)

Otherwise

If Electrical Bus *b* is a component of “Houston 345”

HBDF *b, hb, ERCOT345Bus* = IF(B *hb, Houston345*=0, 0, 1 **/** B *hb, Houston345*)

Otherwise

HBDF *b, hb, ERCOT345Bus* = IF(B *hb, West345*=0, 0, 1 **/** B *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.” |

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 MIS Public area. 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) Service 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; and

(iv) Non-Spinning Reserve (Non-Spin) Service as a Controllable Load Resource qualified for SCED Dispatch;

(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

(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 with a Real-Time Market (RTM) Energy Bid is its Load Zone Settlement Point.

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

3.6.2 Decision-Making Authority for a SCED-Qualified Controllable Load Resource

(1) Each Resource Entity for a SCED-qualified Controllable Load Resource shall submit a declaration to ERCOT, using Section 23, Form C, Managed Capacity Declaration, as to which Entity has the decision-making authority for each of its SCED-qualified Controllable Load Resources. The declaration shall be signed by the Authorized Representative of the Resource Entity. In addition, each Resource Entity that owns a SCED-qualified Controllable Load Resource 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. Upon ERCOT’s request, each Resource Entity for a SCED-qualified Controllable Load Resource shall provide ERCOT with sufficient information or documentation to verify control of the Resource. ERCOT shall apply decision-making authority to Managed Capacity for an Entity effective the first Operating Hour of the Operating Day 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. “Managed Capacity for an Entity” is a SCED-qualified Controllable Load Resource for which the Entity or its Affiliates has the decision-making authority over how the Resource is bid, in accordance with subsection (d) of P.U.C. Subst. R. 25.502, Pricing Safeguards in Markets Operated by the Electric Reliability Council of Texas.

3.7 Resource Parameters

(1) A Resource Entity shall register All-Inclusive 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.

***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, and Hydro Generation Resources

### 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.

(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.

(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.”

(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.

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.

(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.

(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) Service.

(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.

(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 Hydro Generation Resources

(1) A QSE is considered to have performed for the amount of its RRS obligation for the MW amount provided by a hydro 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)(b) of Section 3.18, Resource Limits in Providing Ancillary Service, without corresponding RRS deployment by ERCOT. This provision applies only for the duration when hydro RRS MW is deployed by automatic under-frequency relay action.

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.

(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, 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.

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.

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

(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;

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

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

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

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

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

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

(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 (hydro) providing Responsive Reserve (RRS) but unavailable for Dispatch by SCED and available for commitment by RUC;

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

(M) 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; and

(N) 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.

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

(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;

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

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

(D) EMR – Available for commitment as a Resource contracted by ERCOT under Section 3.14.1, Reliability Must Run, or under paragraph (2) 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; and

(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 Service, excluding Controllable Load Resources; and

(F) OUTL – Not available;

(c) The HSL;

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

(d) The LSL;

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

(e) The High Emergency Limit (HEL);

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

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

(i) Regulation Up (Reg-Up);

(ii) Regulation Down (Reg-Down);

(iii) RRS Service; and

(iv) Non-Spin.

(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).

(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.

(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 (2) 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 (2) 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.

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.

(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.

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.

(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.

(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.

(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 Critical Energy Infrastructure Information (CEII) standards. 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.

(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.

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.

(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 All-Inclusive Generation Resource as described in Planning Guide Section 5, Generation Resource Interconnection or Change Request, it must meet the conditions of Planning Guide Section 6.9, Addition of Proposed Generation to the Planning Models, for inclusion in the planning models before submitting a change to the Network Operations Model to reflect the new All-Inclusive Generation Resource.

(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 MIS Public Area.

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

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

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

3.10.2 Annual Planning Model

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

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

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

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

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

3.10.3 CRR Network Model

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

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

(3) Each CRR Network Model must include:

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

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

(c) Generation Resource locations;

(d) Transmission Elements;

(e) Transmission impedances;

(f) Transmission ratings;

(g) Contingency lists;

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

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

(4) ERCOT shall make available to TSPs and/or DSPs and all appropriate Market Participants, consistent with applicable policies regarding release of CEII, the CRR Network Model. ERCOT shall provide model information through the use of the EPRI and NERC-sponsored CIM and web based XML communications or PSS/E format.

**3.10.3.1 Process for Managing Changes in Updated Network Operations Model for Resource Retirements or Point of Interconnection Changes**

(1) Following the permanent change in Point of Interconnection (POI) of all Resources associated with a Resource Node, ERCOT shall retain the associated Settlement Point in the Network Operations Model at its existing location or an electrically similar location until all outstanding CRRs associated with that Settlement Point have expired. Following the retirement of all Resources associated with a Resource Node, ERCOT shall move the Resource Node to a proxy Electrical Bus. The proxy Electrical Bus will be selected by finding the nearest energized Electrical Bus at the same voltage level with the least impedance equipment between the retired Resource Node and the proxy Electrical Bus. For purposes of the CRR Auction model for calendar periods that are prior to the expiration date of all CRRs associated with the Settlement Point, the Settlement Point will continue to be available as a sink or source for CRR Auction transaction submittals. For calendar months that are beyond the expiration date of all CRRs associated with the Settlement Point, the Settlement Point will not be available for transaction submittals in the associated CRR Auctions. The Settlement Point will be removed from the Network Operations Model once all associated CRRs have expired.

3.10.4 ERCOT Responsibilities

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

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

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

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

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

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

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

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

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

3.10.5 TSP Responsibilities

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

(2) TSPs shall add telemetry at ERCOT’s request to maintain observability and redundancy requirements as specified herein, and under Section 3.10.7.5. ERCOT shall request such additions when a lack of data telemetry has caused, or can be demonstrated to result in, inaccuracies between Real-Time measurements and modeling outcomes that could result in incorrect LMP prices or potential reliability problems.

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

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

3.10.6 Resource Entity Responsibilities

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

3.10.7 ERCOT System Modeling Requirements

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

**3.10.7.1 Modeling of Transmission Elements and Parameters**

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

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

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

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

3.10.7.1.1 Transmission Lines

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

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

(a) Equipment owner(s);

(b) Equipment operator(s);

(c) Transmission Element name;

(d) Line impedance;

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

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

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

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

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

3.10.7.1.2 Transmission Buses

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

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

(a) Equipment owner(s);

(b) Equipment operator(s);

(c) The Transmission Element name;

(d) The substation name;

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

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

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

3.10.7.1.3 Transmission Breakers and Switches

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

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

(a) Equipment owner(s);

(b) Equipment operator(s);

(c) The Transmission Element name;

(d) The substation name;

(e) Connectivity;

(f) Normal status;

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

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

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

3.10.7.1.4 Transmission and Generation Resource Step-Up Transformers

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

(2) ERCOT shall model all Generation Resource step-up transformers greater than ten MVA to provide for accurate representation of generator voltage control capability including the capability to accept a system operator entry of a specific no-load tap position, or if changeable under Load, accept telemetry of the current tap position.

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

(a) Equipment owner(s);

(b) Equipment operator(s);

(c) The Transmission Element name;

(d) The substation name;

(e) Winding ratings;

(f) Connectivity;

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

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

(4) The Resource Entity shall provide parameters for each step-up transformer to ERCOT as part of the Resource Registration data pursuant to Planning Guide Section 6.8.2, Resource Registration Process. ERCOT shall provide the information to TSPs. Each TSP shall coordinate with the operators of the Resources connected to their respective systems to establish the proper transformer tap positions (no-load taps) and the equipment owner shall report any changes to ERCOT using the NOMCR process or other ERCOT prescribed means. Each Resource Entity and each TSP shall schedule generation Outages at mutually agreeable times to implement tap position changes when necessary. If mutual agreement cannot be reached, then ERCOT shall decide where to set the tap position to be implemented by the Resource Entity at the next generation Outage, considering expected impact on system security, future Outage plans, and participants. TSPs shall provide ERCOT and Market Participants with notice in accordance with paragraph (4) of 3.10.4, ERCOT Responsibilities, paragraph (4) (except for emergency) prior to the tap position change implementation date.

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

3.10.7.1.5 Reactors, Capacitors, and other Reactive Controlled Sources

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

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

(a) Equipment owner(s);

(b) Equipment operator(s);

(c) The Transmission Element name;

(d) The substation name;

(e) Voltage or time switched on;

(f) Voltage or time switched off;

(g) Associated switching device name;

(h) Connectivity;

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

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

(3) The ERCOT Operating Guides must include parameters for standard reactor and capacitor switching plans for use in the Network Operations Model. ERCOT shall model the devices under Section 3.10.4, ERCOT Responsibilities, in all applicable ERCOT applications and systems. ERCOT shall provide copies of the switching plan to the Market Participants via the MIS Secure Area. Any change in TSP guidelines or switching plan must be provided to ERCOT before implementation (except for emergency). Any change in guidelines or switching plan must be provided in accordance with the NOMCR process or other ERCOT-prescribed process.

**3.10.7.2 Modeling of Resources and Transmission Loads**

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

(2) Each Resource Entity shall provide ERCOT and TSPs with information describing each of its Aggregate Load Resources (ALRs) as specified in Section 3.7.1.2, Load Resource Parameters, and any additional information and telemetry as required by ERCOT, in accordance with the timelines set forth in Section 3.10.1, Time Line for Network Operations Model Changes. ERCOT shall coordinate the modeling of ALRs with their representatives to ensure consistency between TSP models and ERCOT models.

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| --- |
| ***[NPRR866: Replace paragraph (2) above with the following upon system implementation:]***  (2) Each Resource Entity representing either a Load Resource or an Aggregate Load Resource (ALR) shall provide ERCOT and, as applicable, its interconnecting DSP and TSP, with information describing each such Resource as specified in Section 3.7.1.2, Load Resource Parameters, and any additional information and telemetry as required by ERCOT, in accordance with the timelines set forth in Section 3.10.1, Time Line for Network Operations Model Changes. ERCOT shall coordinate the modeling of ALRs with Resource Entities. ERCOT shall coordinate with representatives of the Resource Entity to map Load Resources to their appropriate Load in the Network Operations Model. |

|  |
| --- |
| ***[NPRR866: Insert paragraph (3) below upon system implementation and renumber accordingly:]***  (3) Each Resource Entity representing a Distributed Generation (DG) facility that is registered with ERCOT pursuant to paragraph (5) of Section 16.5, Registration of a Resource Entity, shall provide ERCOT, its interconnecting DSP, and the TSP that interconnects the DSP to the transmission system with information describing each of its registered DG facilities, and additional information and telemetry as required by ERCOT. ERCOT shall coordinate with representatives of the Resource Entity to map registered DG facilities to their appropriate Load in the Network Operations Model. |

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

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

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

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

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

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

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

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

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

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

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

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

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

(e) Either:

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

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

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

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

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

***3.10.7.2.1 Reporting of Demand Response***

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

(2) On an annual basis, ERCOT shall work with Market Participants to produce a report summarizing Demand response programs, and MWs enrolled in Demand response in the ERCOT Region. This report shall be posted to the MIS Public Area no later than March 31st of each calendar year.

**3.10.7.3 Modeling of Private Use Networks**

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

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

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

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

(iii) Contains generation registered to provide Ancillary Services.

(b) A Generation Entity with a generator greater than ten MW located within a Private Use Network which does not meet any of the criteria of item (a) above shall provide to ERCOT annually, or more often upon change, the following information for ERCOT’s use in the Network Operations Model, for each of its individual generating unit(s) located within the Private Use Network:

(i) Equipment owner(s);

(ii) Equipment operator(s);

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

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

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

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

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

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

(ix) Other interconnection data as required by ERCOT.

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

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

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

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

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

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

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

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

**3.10.7.5 Telemetry Standards**

(1) ERCOT and the appropriate TAC subcommittee shall annually review the Telemetry Standards to determine if updates are necessary. The TAC shall approve updates to the Telemetry Standards.

(2) The Telemetry Standards must define the performance and observability requirements of voltage and power flow measurements, including requirements for redundancy of telemetry measurement data, necessary to support the SE in meeting the State Estimator Standards.

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

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

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

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

(5) When ERCOT identifies a reliability concern, a deficiency in system observability, or a deficiency in measurement to support the representation of Model Loads, and that concern or deficiency is not due to any inadequacy of the SE program, ERCOT may request that a TSP or QSE provide additional telemetry measurements, beyond those required by the Telemetry Standards, in a reasonable time frame for providing such measurements. Such requests must be submitted to the TSP or QSE with a written justification for the additional telemetry measurements. Such written justification must include documentation of the deficiency in system observability or representation of Model Loads. In making the determination to request additional telemetry measurements, ERCOT shall consider the economic implications of inaccurate representation of Load models in LMP results versus the cost to remedy.

(6) Within 30 days of submittal by ERCOT to the designated contact of a TSP or QSE with a written request justifying additional telemetry measurements, the TSP or QSE shall acknowledge the request and either:

(a) Agree with the request and make reasonable effort to install new equipment providing measurements to ERCOT within the timeframe specified;

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

(c) If the TSP or QSE disagrees with the request, appeal that request to TAC or present an alternate solution to ERCOT for consideration.

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

3.10.7.5.1 Continuous Telemetry of the Status of Breakers and Switches

(1) Each TSP and QSE shall provide telemetry, as described in this subsection, to ERCOT on the status of all breakers and switches used to switch any Transmission Element or Load modeled by ERCOT. Each TSP and QSE is not required to install telemetry on individual breakers and switches, where the telemetered status shown to ERCOT is current and free from ambiguous changes in state caused by the TSP or QSE switching operations and TSP or QSE personnel. Each TSP or QSE shall update the status of any breaker or switch through manual entries, if necessary, to communicate the actual current state of the device to ERCOT, except if the change in state is expected to return to the prior state within one minute. If in the sole opinion of ERCOT, the manual updates of the TSP or QSE have been unsuccessful in maintaining the accuracy required to support SE performance to a TAC-approved predefined standard as described in Section 3.10.9, State Estimator Standards, ERCOT may request that the TSP or QSE install complete telemetry from the breaker or switch to the TSP or QSE, and then to ERCOT. In making the determination to request installation of additional telemetry from a breaker or switch, ERCOT shall consider the economic implications of inaccurate representation of Model Loads in LMP results versus the cost to remedy.

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

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

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

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

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

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

(1) Each TSP or QSE shall provide telemetry of voltages, flows, and Loads on any modeled Transmission Element to the extent such may be required to estimate all transmission Load withdrawals and generation injections to and from the ERCOT Transmission Grid using the SE and as needed to achieve the State Estimator Standards with consideration given to the economic implications of inaccurate LMP results versus the cost to remedy.

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

(3) Each TSP shall provide telemetered measurements on modeled Transmission Elements to ensure SE observability, per the Telemetry Standards, of any monitored voltage and power flow between their associated transmission breakers to the extent such can be shown to be needed in achieving the State Estimator Standards. On monitored non-Load substations, each TSP shall install, at the direction of ERCOT, sufficient telemetry such that there is an “N-1 Redundancy.” An N-1 Redundancy exists if the substation remains observable on the loss of any single measurement pair (kW, kVAr) excluding station RTU communication path failures. In making the determination to request additional telemetry, ERCOT shall consider the economic implications of inaccurate representation of Load models in LMP results versus the cost to remedy.

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

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

(a) Five percent of the largest line Normal Rating at the SE Bus; or

(b) Five MW, whichever is greater.

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

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

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

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

**3.10.7.6 Use of Generic Transmission Constraints and Generic Transmission Limits**

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

(2) During the ERCOT quarterly stability assessment, performed pursuant to Planning Guide Section 5.9, Quarterly Stability Assessment, if ERCOT determines a GTC is necessary for a new All-Inclusive Generation Resource due to localized stability issues associated with the output of the interconnecting All-Inclusive Generation Resource, the GTL for the GTC shall be set to the lowest non-zero limit for all system conditions outside those in which the limit is zero.

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

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

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

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

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

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

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

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

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| ***[NPRR809: Insert paragraph (7) below upon system implementation:]***  (7) No later than 180 days after the effective date of a new GTC, ERCOT shall post a report listing alternatives for exiting the GTC to the MIS Secure Area. The listed alternatives may include but are not limited to the implementation or modification of a RAS or a transmission improvement project. |

**3.10.7.7** **DC Tie Limits**

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

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

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| ***[NPRR825: Replace Section 3.10.7.7 above with the following upon system implementation:]***  **3.10.7.7** **DC Tie Advisory Limits**  (1) Every hour, ERCOT shall post DC Tie advisory limits for each hour of the next 48 hours to the MIS Secure Area. ERCOT may update these limits as system conditions change. Any updated DC Tie advisory limits shall be posted to the MIS Secure Area as soon as practicable.  (2) DC Tie advisory limits shall be based on expected, or actual system conditions, including Outages, for each hour of the Operating Day and shall be calculated as the lower of the available physical capacity of the DC Tie, the amount of DC Tie import and export that could flow without resulting in transmission security violations that would not be resolved by SCED, or, for the DC Ties with Mexico, any limits supplied by the Mexican system operator. In setting these limits for a given hour, ERCOT shall assume that any Generation Resource shown to be available in its COP for a given hour will be self-committed or committed at the appropriate time through the Reliability Unit Commitment (RUC) process to resolve any transmission security violations resulting from DC Tie Schedules. DC Tie Schedules are subject to the actual availability of that generation at the time the Generation Resource is needed, as well as other system conditions. |

3.10.8 Dynamic Ratings

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

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

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

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

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

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

**3.10.8.1 Dynamic Ratings Delivered via ICCP**

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

(a) Normal Rating; and

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

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

**3.10.8.2 Dynamic Ratings Delivered via Static Table and Telemetered Temperature**

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

(a) Line ID;

(b) From station;

(c) To station;

(d) Weather Zone(s);

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

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

(2) If a TSP is providing a current temperature for each applicable Weather Zone through SCADA telemetry then ERCOT shall determine the appropriate rating based upon the telemetered temperature, and adjust the Normal Rating, Emergency Rating, and 15-Minute Rating within five minutes of receipt for the next Operating Hour. ERCOT shall use the Dynamic Ratings in its SCADA alarming, real-time Security Analysis, and SCED process.

**3.10.8.3 Dynamic Rating Network Operations Model Change Requests**

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

**3.10.8.4 ERCOT Responsibilities Related to Dynamic Ratings**

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

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

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

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

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

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

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

**3.10.8.5 Transmission Service Provider Responsibilities Related to Dynamic Ratings**

(1) Each TSP shall:

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

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

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

3.10.9 State Estimator Standards

(1) ERCOT and the appropriate TAC subcommittee shall annually review the State Estimator Standards to determine if updates are necessary. TAC shall approve any updates to the State Estimator Standards.

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

**3.10.9.1 Considerations for State Estimator Standards**

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

(a) Desired confidence levels of SE results;

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

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

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

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

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

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

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

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

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

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

(ix) Other parameters or circumstances, as appropriate;

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

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

(e) Other parameters as deemed appropriate.

**3.10.9.2 Telemetry and State Estimator Performance Monitoring**

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

3.11 Transmission Planning

3.11.1 Overview

(1) Project endorsement through the ERCOT regional planning process is intended to support, to the extent applicable, a finding by the Public Utility Commission of Texas (PUCT) that a project is necessary for the service, accommodation, convenience, or safety of the public within the meaning of Public Utility Regulatory Act, Tex. Util. Code Ann. § 37.056 (Vernon 1998 and Supp. 2007) (PURA) and P.U.C. Subst. R. 25.101, Certification Criteria.

3.11.2 Planning Criteria

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

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

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

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

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

(6) Other indicators based on analyses of ERCOT System operations may be considered as appropriate in the determination of benefits. In order for such an alternate indicator to be considered, the costs must be reasonably expected to be on-going and be adequately quantifiable and unavoidable given the physical limitation of the transmission system. These alternate indicators include:

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

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

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

3.11.3 Regional Planning Group

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

***3.11.4 Regional Planning Group Project Review Process***

**3.11.4.1 Project Submission**

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

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

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

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

**3.11.4.2 Project Comment Process**

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

**3.11.4.3 Categorization of Proposed Transmission Projects**

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

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

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

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

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

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| ***[NPRR837: Insert paragraph (ii) below on July 1, 2020:]***  (ii) The estimated capital cost is less than $25,000,000, a CCN is not required, and the project includes 345 kV circuit reconductor of more than one mile, additional 345/138 kV autotransformer capacity, or a new 345 kV substation, unless the project is considered to be a neutral project pursuant to paragraph (f) below. |

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| ***[NPRR837: Insert paragraph (d) below on July 1, 2020 and renumber accordingly:]***  (d) A project with an estimated capital cost greater than or equal to $25,000,000 that is proposed for the purpose of replacing aged infrastructure or storm hardening shall be processed as a Tier 3 project and shall be reclassified as a Tier 4, neutral project upon ERCOT’s determination that any concerns, questions or objections raised during the comment process have been resolved satisfactorily. |

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

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

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

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

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

(iv) Projects that are associated with the direct interconnection of new generation;

(v) The addition of static reactive devices;

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

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

(viii) Equipment upgrades resulting in only ratings changes.

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

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

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

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

**3.11.4.4 Processing of Tier 4 Projects**

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

**3.11.4.5 Processing of Tier 3 Projects**

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

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

**3.11.4.6 Processing of Tier 2 Projects**

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

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

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

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

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

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

**3.11.4.7 Processing of Tier 1 Projects**

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

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

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

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

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

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

(2) Tier 1 projects require ERCOT Board endorsement.

**3.11.4.8 Determine Designated Providers of Transmission Additions**

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

**3.11.4.9 Regional Planning Group Acceptance and ERCOT Endorsement**

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

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

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

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

**3.11.4.10 Modifications to ERCOT Endorsed Projects**

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

(2) For economic-driven projects, if a TSP determines that the estimated project cost has increased by more than 10% over the cost described in ERCOT’s endorsement, the TSP shall notify RPG prior to filing a CCN application if required, or prior to beginning the final design of the project if no CCN application is required, and provide an explanation for the cost increase. For comparison purposes, the cost of the route that best meets PUCT criteria will be used.

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

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

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

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

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

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

3.11.6 Generation Interconnection Process

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

(2) ERCOT shall perform an independent economic analysis of the transmission projects that are identified through this process that are expected to cost more than $25,000,000. This economic analysis is performed only for informational purposes; as such, no ERCOT endorsement will be provided. The results of the economic analysis shall be included in the interconnection study posting.

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

3.12 Load Forecasting

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

(a) ERCOT shall update and post hourly on the Market Information System (MIS) Public Area, a “Seven-Day Load Forecast” as described in Section 3.12.1, Seven-Day Load Forecast, that provides forecasted hourly Load over the next 168 hours for each of the Weather Zones and for each of the Forecast Zones.

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

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| ***[NPRR873: Insert paragraph (2) below upon system implementation:]***  (2) ERCOT shall produce and post to the MIS Public Area an Intra-Hour Load Forecast (IHLF) that provides a rolling two hour five minute forecast of ERCOT-wide Load. |

3.12.1 Seven-Day Load Forecast

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

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

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

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

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

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| ***[NPRR842: Insert Section 3.12.2 below upon system implementation:]***  ***3.12.2 Study Areas***  (1) ERCOT shall develop and use Study Areas for Load forecasting and study purposes, and will provide the Load forecast data to the market. A list of Study Areas shall be available on the MIS Public Area. |

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| ***[NPRR842: Insert Section 3.12.3 below upon system implementation:]***  3.12.3 Seven-Day Study Area Load Forecast  (1) ERCOT shall develop and post hourly on the MIS Public Area a “Seven-Day Study Area Load Forecast” to predict the hourly Loads for the next 168 hours based on current weather forecast parameters within each Study Area.  (a) The forecast referenced in paragraph (1) above will not affect the values within the “Seven-Day Load Forecast” by Weather Zone and/or Forecast Zone. |

3.13 Renewable Production Potential Forecasts

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

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

3.14 Contracts for Reliability Resources and Emergency Response Service Resources

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

3.14.1 Reliability Must Run

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

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

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

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

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

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

(iv) Load response alternatives once a suitable Load response service is defined and available; and

(v) Resource alternatives, including capabilities of Distributed Generation (DG), Load Resources, Direct Current Ties (DC Ties), Block Load Transfers (BLTs), etc.

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

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

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

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

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| ***[NPRR664: Replace paragraph (f) above with the following upon system implementation:]***  (f) A Generation Resource is eligible for RMR status based on criteria established by ERCOT indicating its operation is necessary to support ERCOT System reliability according to the Operating Guides. A combined-cycle generation Facility must be treated as a single unit for RMR purposes unless the combustion turbine and the steam turbine can operate separately. If the steam turbine and combustion turbine can operate separately, and the steam turbine is powered by waste heat from more than one combustion turbine, the combustion turbine accepted for RMR Service and a proportionate part of the steam turbine must be treated as a single unit for RMR purposes. If the combustion turbine accepted for RMR Service can operate separately from the steam turbine, and only the combustion turbine is accepted as an RMR Unit, the RMR energy price will be reduced by the value of the combustion turbine’s waste heat calculated at the Fuel Index Price for Resource (FIPRr), except when the steam turbine is Off-Line. ERCOT shall post to the MIS Secure Area the criteria upon which it evaluates whether an RMR Unit meets the test of operational necessity to support ERCOT System reliability within five Business Days of change and shall issue a Market Notice stating the determination is available. This includes the case where a unit previously identified by ERCOT as potentially needed for RMR Service is no longer needed regardless of whether an RMR Agreement was ever signed. |

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

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

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

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

(i) Participating in the bilateral energy market;

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

(iii) Providing of Ancillary Service to any Entity.

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

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

**3.14.1.1 Notification of Suspension of Operations**

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

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

(3) A Resource Entity ceasing or suspending operations as a result of a Forced Outage lasting greater than 180 days shall notify ERCOT as soon as practicable. An NSO submitted due to a Forced Outage will not be evaluated for RMR status and will not be posted on the MIS.

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

**3.14.1.2 ERCOT Evaluation**

(1) Upon receipt of an NSO under Section 3.14.1.1, Notification of Suspension of Operations, ERCOT shall post the NSO on the MIS Secure Area and shall post all existing relevant studies and data and provide a Market Notice of the application and posting of the studies and data.

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

(3) ERCOT shall conduct a reliability analysis of the need for the Generation Resource(s) to support ERCOT System reliability.

(a) ERCOT shall use the most recent Steady State Working Group (SSWG) base cases in the reliability analysis. ERCOT shall use a Load forecast consistent with current Regional Transmission Plan assumptions and methodologies for the appropriate season(s). If additional new Generation Resources meet the criteria in Planning Guide Section 6.9, Addition of Proposed Generation to the Planning Models, ERCOT shall update the base case to include those additional Generation Resources with the appropriate seasonal ratings.

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

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

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

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

(A) Pre-contingency;

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

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

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

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

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

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

(d) If the reliability analysis described in paragraphs (a)-(c) above is performed and if the analysis identifies any deficiencies for which the Generation Resource has a material impact during the two year planning horizon, ERCOT shall pursue solutions to those deficiencies in the following order of priority:

(i) Alternatives outlined in paragraph (1)(b) of Section 3.14.1, Reliability Must Run, as well as any other operational alternatives deemed to be viable by ERCOT.

(ii) Transmission upgrades that do not require a Certificate of Convenience and Necessity (CCN) or new rights-of-way that can be implemented prior to the time period that the performance deficiency has been identified.

(iii) Transmission upgrades that require a CCN or new rights-of-way that will eliminate the performance deficiency prior to the time period that the deficiency has been identified.

(iv) If items (i) through (iii) above do not resolve the deficiency, then ERCOT shall attempt to enter into an RMR or Must-Run Alternative (MRA) Agreement to address the deficiency, if ERCOT determines it is cost-effective to do so. ERCOT is not required to attempt to enter into an MRA Agreement if the Generation Resource is mothballed on a seasonal basis.

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

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

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

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

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

(5) Within 60 days after receiving Part I and Part II of the NSO, ERCOT shall complete its reliability analysis described in paragraph (3) above. ERCOT shall issue a Market Notice describing the results of its reliability analysis prior to entering RMR Agreement negotiations with the Resource Entity. Not later than 14 days after completing its reliability analysis, ERCOT shall issue a Market Notice on the status of negotiations with the Generation Resource and on the status of procurement of an MRA. If ERCOT determines that the Generation Resource is not needed to support ERCOT System reliability, then the Generation Resource may cease or suspend operations according to the schedule in its NSO, unless ERCOT in its sole discretion permits the Generation Resource to suspend operations at an earlier date, and ERCOT shall note this in the Market Notice.

(6) Within ten days after a determination by ERCOT that the proposed suspension of the Generation Resource would result in a performance deficiency on which the Generation Resource has a material impact, as described in this Section, the Resource Entity shall, if it has not already done so, complete and submit to ERCOT Part III of the NSO (Section 22, Attachment E, Notification of Suspension of Operations). ERCOT shall post the Part III information on the MIS Secure Area. On the 11th day after the determination or on receipt of Part III of the NSO, whichever comes first, ERCOT and the Resource Entity shall begin good faith negotiations on an RMR Agreement. These negotiations shall include the budgeting process for Eligible Costs and for fuel costs as detailed in Section 3.14.1.11, Budgeting Eligible Costs, and Section 3.14.1.17, Budgeting Fuel Costs.

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

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

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

**3.14.1.2.1 ERCOT Evaluation of Seasonal Mothball Status**

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

(2) Within 30 days after receiving the NSO described in Section 3.14.1.1, Notification of Suspension of Operations, ERCOT shall make an initial assessment of whether the Generation Resource is required to support ERCOT System reliability during the portion of the year when the Generation Resource would be unavailable.

(3) Within 60 days after receiving the NSO ERCOT shall make a final assessment of whether the Generation Resource is required to support ERCOT System reliability during the portion of the year when the Generation Resource would be unavailable.

**3.14.1.3 ERCOT Board Approval of RMR and MRA Agreements**

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

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

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

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

(d) ERCOT evaluated:

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

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

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

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

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

**3.14.1.4 Exit Strategy from an RMR Agreement**

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

**3.14.1.5 Potential Alternatives to RMR Agreements**

(1) ERCOT shall provide reasonably available information that would enable potential MRAs to assess the feasibility of submitting a proposal to provide a more cost‑effective alternative to an RMR Unit through the regional planning process, including any known minimum technical requirements and/or operational characteristics required to eliminate the need for the RMR Unit. TAC shall review the output of the regional planning process and provide guidance prior to entering into an agreement with an MRA (MRA Agreement).

(2) After the process identified in paragraph (1) above, and subsequent to the issuance of a Market Notice on the intent to enter into an MRA Agreement detailing the solution, location and MW as applicable, ERCOT may negotiate a contract for an MRA that:

(a) Technically provides an acceptable solution to the reliability concern that would otherwise be solved by the RMR Unit(s);

(b) Will provide a more cost effective alternative to continued service by the RMR Unit (evaluated over the exit strategy period); provided, however, that no proposed MRA will be considered if it does not provide at least $1 million in annual savings over the projected net annualized costs for the RMR Unit; and

(c) Satisfies objective financial criteria to demonstrate that the seller is reasonably able to fulfill its performance obligations as determined by ERCOT.

(3) If the resulting MRA Agreement would result in significantly lower total costs than continued service by the RMR Agreement, and otherwise meets the requirements of this subsection, ERCOT may sign the MRA Agreement, pursuant to Section 3.14.1.3, ERCOT Board Approval of RMR and MRA Agreements. ERCOT shall issue a Market Notice documenting the solution, location(s), and expected MW and duration of supply, as applicable, within 24 hours of signing the MRA Agreement. The term of the MRA Agreement must be limited to the time period until the cost effective exit strategy can be implemented.

(4) If the execution of an MRA Agreement would result in the foreclosure of other technically viable solutions (e.g*.*, the RMR Unit that is being replaced by the MRA Agreement retires and is no longer available as an alternative to the MRA Agreement), the MRA Agreement shall include terms and conditions that limit the MRA owner’s ability to withdraw or raise the price of the MRA Agreement in future years until an exit strategy can be implemented.

(5) For any MRA Agreement entered into by ERCOT, ERCOT shall annually update the list of feasible alternatives developed in Section 3.14.1.4, Exit Strategy from an RMR Agreement, and provide an update of that information to the TAC and the ERCOT Board.

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

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

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

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

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

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

**3.14.1.7 RMR or MRA Contract Termination**

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

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

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

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

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

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

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

**3.14.1.8 RMR and/or MRA Contract Extension**

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

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

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

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

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

**3.14.1.9 Generation Resource Status Updates**

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

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

(3) A Mothballed Generation Resource that operates under a Seasonal Operation Period shall remain modeled in all ERCOT systems at all times, (i.e., will not be flagged as “mothballed” in ERCOT’s models) and, when it is not available, the Resource Entity shall designate the Generation Resource as on Planned Outage in the Outage Scheduler.

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

(5) If a Resource Entity wishes to change the operational designation of a Generation Resource upon conclusion of an RMR Agreement, it must submit a Notification of Change of Generation Resource Designation no later than 60 days prior to the conclusion of the RMR Agreement.

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

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

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

(9) A Resource Entity with a Mothballed Generation Resource that operates under a Seasonal Operation Period must notify ERCOT in writing, by completing an NSO (Section 22, Attachment E), no less than 90 days before the date on which the Mothballed Generation Resource that operates under a Seasonal Operation Period is to be suspended indefinitely or retired and decommissioned.

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

(11) If ERCOT and the Resource Entity or QSE cannot reach a mutual agreement to make the Mothballed Generation Resource operating under a Seasonal Operation Period available earlier than June 1**st** or later than September 30**th** of any given calendar year, then ERCOT may exercise its ability to bring the Mothballed Generation Resource operating under a Seasonal Operating Period into the market under an RMR Agreement pursuant to paragraph (2) of Section 6.5.1.1, ERCOT Control Area Authority.

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

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

(14) Before retiring and decommissioning either a Mothballed Generation Resource other than a Mothballed Generation Resource operating under a Seasonal Operation Period or an RMR Unit that would otherwise become a Mothballed Generation Resource upon expiration of an RMR Agreement, a Resource Entity shall notify ERCOT of the expected retirement by submitting a completed Notification of Change of Generation Resource Designation form (Section 22, Attachment H). The date of retirement indicated on the form shall comply with the requirements of Section 3.10.1, Time Line for Network Operations Model Changes.

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

**3.14.1.10 Eligible Costs**

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

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

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

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

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

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

(v) Costs associated with maintenance:

(A) Due to required equipment maintenance;

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

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

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

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

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

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

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

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

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

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

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

(x) Non-fuel costs to return a mothballed RMR Unit to service provided that:

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

(B) The costs do not include costs the RMR Unit would have incurred had it remained mothballed.

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

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

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

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

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

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

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

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

**3.14.1.11 Budgeting Eligible Costs**

(1) The owner of an RMR Unit shall provide a good faith preliminary budget, including detailed monthly estimates of its Eligible Costs to ERCOT as part of the RMR Agreement negotiation process as described in paragraph (3) below, in a format acceptable to ERCOT. ERCOT shall review and may approve the budget and use these figures as the basis for calculating the Standby Price ($/Hour) which is paid on the Initial Settlement for RMR Service. Actual Eligible Costs incurred by the RMR Unit will be used for subsequent Final, Resettlement, or True-Up Settlements as agreed upon in Section 6.6.6, Reliability Must-Run Settlement.

(2) As part of the MRA evaluation process, the QSE that represents the MRA must notify ERCOT if any contributed capital expenditures are required under the proposed MRA Agreement. The QSE that represents the MRA shall provide an explanation and a good faith preliminary budget for the contributed capital expenditures in a format acceptable to ERCOT. ERCOT shall review and may approve the budget to determine which costs would be considered contributed capital expenditures in accordance with Section 3.14.1.16, Charge for Contributed Capital Expenditures.

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

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

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

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

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

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

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

(iv) Variable Operations and Maintenance (O&M) costs, unless the RMR Unit had been previously approved for verifiable costs;

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

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

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

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

(4) Upon commencement of the RMR Agreement, the RMR Unit owner shall submit to ERCOT quarterly updated budget information, in a format consistent with the preliminary budget, for the remainder of the term of the RMR Agreement.

**3.14.1.12 Reporting Actual RMR Eligible Costs**

(1) The RMR Unit owner shall provide ERCOT with actual Eligible Costs on a monthly basis in a level of detail sufficient for ERCOT to verify that all Eligible Costs are actual and appropriate. Submitted actual Eligible Costs must be categorized consistently with budgeted Eligible Costs. Actual cost data must be submitted on time by the Resource Entity for the RMR Unit and then verified by ERCOT so the actual cost data can be reflected in the True-Up Settlement Statement. To be considered timely for the final, actual cost data for month ‘x’ must be submitted by the 16th of the month following month ‘x’. To be considered timely for the true-up, actual cost data for month ‘x’ must be submitted 30 days prior to the publishing date of the True-Up Settlement Statement for the first day in month ‘x’. Any deviation in filing actual cost data in accordance with this calendar must be requested of ERCOT, by the QSE representing an RMR Unit. Such request for deviation shall contain the reason for the inability to meet the calendar and an expected date that the cost data will be provided to ERCOT. At its discretion ERCOT may choose to honor such a request. No later than two Business Days following its decision, ERCOT shall issue a Market Notice of any such request and its response thereto. In the event, that actual cost data is not submitted in accordance with the calendar or approved deviation for the true-up, then the cost for the portion of eligible cost that has not been submitted is deemed to be zero.

**3.14.1.13 Reporting Actual MRA Eligible Costs**

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

**3.14.1.14 Incentive Factor**

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

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

(3) The Incentive Factor shall be reduced if the “Hourly Rolling Equivalent Availability Factor” of the RMR Unit is less than the Target Availability (i.e. the “Actual Availability”, as defined below, is less than the Target Availability). The reduction will be linear; with a 2% reduction in the Incentive Factor payment for every 1% of the Hourly Rolling Equivalent Availability Factor is less than the Target Availability stated in the RMR Agreement. The RMR Unit’s Actual Availability shall be calculated on an hourly rolling six-month average basis by dividing the number of hours that the RMR Unit was available according to its final COP for each hour of the previous 4380 hours for which availability is required under the RMR Agreement by 4380. If less than 4380 hours for which availability is required under the RMR Agreement have elapsed since the start of the RMR Agreement (“Elapsed Time”), then, for each hour that Elapsed Time is less than 4380, that hour shall be considered as if the RMR Unit was available.

**3.14.1.15 Major Equipment Modifications**

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

**3.14.1.16 Charge for Contributed Capital Expenditures**

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

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

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

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

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

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

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

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

(i) No later than 90 days after termination of the RMR or MRA Agreement, ERCOT shall issue a miscellaneous Invoice charging the QSE for the applicable amounts under paragraphs (a), (b), or (c) above. ERCOT will issue a Market Notice after completion of the collection and disbursement of the repaid contributed capital expenditures.

(ii) ERCOT shall distribute the repayment to QSEs representing Load per Section 6.6.6.6, Method for Collecting and Distributing RMR and MRA Contributed Capital Expenditures.

**3.14.1.17 Budgeting Fuel Costs**

(1) The RMR Unit owner shall supply ERCOT a preliminary fuel cost budget for the 12-month period starting with the anticipated effective date of the RMR Agreement. The fuel cost budget must include information pertaining to the cost of the fuel feedstock, including where appropriate transportation costs and terms, as well as fuel storage costs and terms, and any other fuel contract provisions (e.g. “take or pay” provisions) that may impact the cost of all fuels anticipated to be used by the RMR Unit over the life of the RMR Agreement and must include fuel costs categorized in terms of:

(a) Primary fuel; and

(b) Secondary fuel.

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

**3.14.1.18 Reporting Actual Eligible Fuel Costs**

(1) The RMR Unit owner shall provide ERCOT with actual fuel costs on a monthly basis for the RMR Unit in a level of detail sufficient for ERCOT to verify that all fuel costs are actual and appropriate. The estimated fuel payments may include a fuel adder to better approximate expected actual fuel costs. The fuel adder shall represent the difference between the forecasted average actual future fuel price paid and the forecasted average of the relevant index price (FIP, Fuel Oil Price (FOP) or solid fuel) over the RMR contract period. The fuel adder must also include the forecasted cost of transporting, delivering and fuel imbalances to the Resource. QSEs must provide to ERCOT supporting documentation indicating how the fuel adder was determined. ERCOT shall perform a true-up of the estimated fuel costs using the submitted and verified actual fuel costs for the RMR Unit. Actual cost data must be submitted on time by the Resource Entity for the RMR Unit and then verified by ERCOT so the actual cost data can be reflected in the True-Up Settlement Statement. To be considered timely for the final, actual cost data for month ‘x’ must be submitted by the 16th of the month following month ‘x.’ To be considered timely for the true-up, actual cost data for month ‘x’ must be submitted 30 days prior to the publishing date of the True-Up Settlement Statement for the first day in month ‘x.’ Any deviation in filing actual cost data in accordance with this calendar must be requested of ERCOT, by the QSE representing an RMR Unit. Such request for deviation shall contain the reason for the inability to meet the calendar and an expected date that the cost data will be provided to ERCOT. At its discretion ERCOT may choose to honor such a request. No later than two Business Days following its decision, ERCOT shall issue a Market Notice of any such request and its response thereto. In the event that actual cost data is not submitted in accordance with the timeline or is not an approved deviation for the true-up, then the cost for the portion of Eligible Cost that has not been submitted is deemed to be zero.

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| ***[NPRR664: Replace paragraph (1) above with the following upon system implementation:]***  (1) The RMR Unit owner shall provide ERCOT with actual fuel costs on a monthly basis for the RMR Unit in a level of detail sufficient for ERCOT to verify that all fuel costs are actual and appropriate. The estimated fuel payments may include a fuel adder to better approximate expected actual fuel costs. The fuel adder shall represent the difference between the forecasted average actual future fuel price paid and the forecasted average of the relevant index price (Fuel Index Price for Resource (FIPRr), Fuel Oil Price (FOP) or solid fuel) over the RMR contract period. The fuel adder must also include the forecasted cost of transporting, delivering and fuel imbalances to the Resource. QSEs must provide to ERCOT supporting documentation indicating how the fuel adder was determined. ERCOT shall perform a true-up of the estimated fuel costs using the submitted and verified actual fuel costs for the RMR Unit. Actual cost data must be submitted on time by the Resource Entity for the RMR Unit and then verified by ERCOT so the actual cost data can be reflected in the True-Up Settlement Statement. To be considered timely for the final, actual cost data for month ‘x’ must be submitted by the 16th of the month following month ‘x.’ To be considered timely for the true-up, actual cost data for month ‘x’ must be submitted 30 days prior to the publishing date of the True-Up Settlement Statement for the first day in month ‘x.’ Any deviation in filing actual cost data in accordance with this calendar must be requested of ERCOT, by the QSE representing an RMR Unit. Such request for deviation shall contain the reason for the inability to meet the calendar and an expected date that the cost data will be provided to ERCOT. At its discretion ERCOT may choose to honor such a request. No later than two Business Days following its decision, ERCOT shall issue a Market Notice of any such request and its response thereto. In the event that actual cost data is not submitted in accordance with the timeline or is not an approved deviation for the true-up, then the cost for the portion of Eligible Cost that has not been submitted is deemed to be zero. |

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

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

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

3.14.2 Black Start

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

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

(3) Bids for BSS are due on or before June 1st of each two year period. Bids must be evaluated based on evaluation criteria attached as an appendix to the request for bids and contracted by December 31st for the following two year period. ERCOT shall ensure BSSs are arranged, provided, and deployed as necessary to reenergize the ERCOT System following a Blackout or Partial Blackout.

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

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

(6) ERCOT shall periodically conduct system restoration seminars for all TSPs, Distribution Service Providers (DSPs), QSEs, Resource Entities and other Market Participants.

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

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

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

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

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

***3.14.3 Emergency Response Service***

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

**3.14.3.1 Emergency Response Service Procurement**

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

(a) February through May;

(b) June through September; and

(c) October through January.

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

(a) Weather-Sensitive ERS-10

(b) Non-Weather-Sensitive ERS-10

(c) Weather-Sensitive ERS-30

(d) Non-Weather-Sensitive ERS-30

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(b) For each of any subsequent ERS Contract Periods for a given ERS service type in an ERS Standard Contract Term, any ERS Resource with remaining obligation due to cumulative deployment time of less than eight hours at the end of the last ERS Contract Period shall be obligated for only this remaining deployment time in the new ERS Contract Period.

(c) For each of any subsequent ERS Contract Periods in an ERS Standard Contract Term, ERCOT may renew the obligations of certain ERS Resources as follows:

(i) During the offer submission process, QSEs shall designate on the ERS offer form, which is posted on the ERCOT website, whether an ERS Resource elects to participate in renewal ERS Contract Periods (“renewal opt-in”). Except as provided in paragraph (iv) below, this election is irrevocable once the ERS Resource has been committed for an ERS Standard Contract Term.

(ii) If the obligations of one or more ERS Resources are exhausted before the end of an ERS Standard Contract Term, ERCOT shall determine whether to include renewal opt-ins in the subsequent ERS Contract Period. ERCOT may limit any renewal to one or more ERS Time Periods in which obligations have been exhausted.

(iii) If ERCOT decides to include renewal opt-ins in the subsequent ERS Contract Period, ERCOT shall promptly notify all ERS QSEs as to the ERS Time Periods that it has elected to renew.

(iv) By the end of the second Business Day in any renewal ERS Contract Period, a QSE may revoke the renewal opt-in status of any of its committed ERS Resources for any subsequent ERS Contract Periods within that ERS Standard Contract Term. ERCOT shall develop a method for QSEs to communicate such information.

(v) By the end of the third Business Day in any ERS Contract Period other than the first ERS Contract Period in an ERS Standard Contract Term, ERCOT shall communicate to QSEs a confirmation of the terms of participation for all of their committed ERS Resources.

(19) In any 12-month period beginning on February 1st and ending on January 31st, ERCOT shall not commit dollars toward ERS in excess of the ERS cost cap. ERCOT may determine cost limits for each ERS Standard Contract Term in order to ensure that the ERS cost cap is not exceeded.

(20) If a QSE offers a Weather-Sensitive ERS Load, selects a control group baseline for that ERS Load, and ERCOT determines that the magnitude of the offer relative to the baseline error will prevent accurate determination of the performance, ERCOT shall reject the offer.

(21) ERCOT shall reduce the available expenditure under the ERS cost cap by the value of the amount of ERS Self-Provision. ERCOT shall value ERS Self-Provision at the clearing price multiplied by the total MW of ERS Self-Provision during each relevant ERS Time Period.

(22) ERCOT shall procure ERS Resources for each ERS Time Period using a clearing price. The Emergency Response Service Procurement Methodology, posted on the ERCOT website, is an Other Binding Document that describes the methodology used by ERCOT to procure ERS. ERCOT may consider geographic location and its effect on congestion in making ERS awards. ERCOT may prorate the capacity awarded to an ERS Resource in an ERS Time Period if the capacity offered for that ERS Resource would cost more than the Emergency Response Service Procurement Methodology allows under the time period expenditure limit. Such proration shall only be done if the QSE indicates on its offer for an ERS Resource that the QSE is willing to have the capacity prorated and also has indicated the lowest prorated capacity limit which is acceptable for that ERS Resource. If proration would result in an award below an ERS Resource’s designated prorated capacity limit or below the minimum MW offer applicable to the ERS service type as specified in paragraph (8) above, the offer will not be awarded.

(23) Payments and Self-Provision credits to QSEs representing ERS Resources are subject to adjustments as described in Section 8.1.3.3, Payment Reductions and Suspension of Qualification of Emergency Response Service Resources and/or their Qualified Scheduling Entities. Deployment of ERS Resources will not result in additional payments other than any payment for which the QSE may be eligible through Real-Time energy imbalance or other ERCOT Settlement process.

(24) QSEs representing ERS Resources selected to provide ERS shall execute a Standard Form Emergency Response Service Agreement, as provided in Section 22, Attachment G, Standard Form Emergency Response Service Agreement.

**3.14.3.2 Emergency Response Service Self-Provision**

(1) QSEs may self-provide ERS. A QSE electing to self-provide all or part of its ERS obligation shall provide ERCOT with the following, while adhering to a schedule published by ERCOT:

(a) The maximum MW of capacity the QSE is willing to self-provide for each ERS Time Period for each of the four ERS service types; and

(b) A proxy Load Ratio Share (LRS) specific to each ERS Time Period for which an offer is submitted. Proxy LRS shall be a number between zero and one and determined by the self-providing QSE to represent its estimate of its final LRS to be used in ERS Settlement.

(2) ERS Self-Provision Capacity Upper Limit is defined as the maximum level of self-provided ERS MW capacity for which a QSE may receive credit at Settlement for each ERS service type. During the procurement process, a QSE may elect to use a proxy ERS Self-Provision Capacity Upper Limit (based on the proxy LRS it submitted) to reduce its ERS Self-Provision MW for each ERS service type. After receiving ERS Self-Provision information, ERCOT will award offers for additional MWs of ERS capacity for each ERS service type such that the sum of the following does not exceed the total amount of ERS capacity ERCOT intends to procure for that ERS service type in any one ERS Time Period:

(a) ERS capacity awarded through ERS competitive offers; and

(b) ERS capacity awarded through ERS Self-Provision offers, where for each self-providing QSE the self-provided capacity offer is the lesser of the amount offered or the QSE’s proxy ERS Self-Provision Capacity Upper Limit.

(3) The calculations used to determine a QSE’s proxy ERS Self-Provision Capacity Upper Limit for each ERS service type for the ERS procurement phase are the same as those used to determine the actual ERS Self-Provision Capacity Upper Limit for Settlement, as described in Section 6.6.11.1, Emergency Response Service Capacity Payments, except that:

(a) Offered ERS capacity is substituted for delivered ERS capacity; and

(b) A QSE’s proxy LRS is substituted for its actual LRS.

(4) ERCOT shall compute and provide QSEs offering ERS Self-Provision their proxy ERS Self-Provision Capacity Upper Limit for each ERS service type. A QSE may then reduce any or all of its self-provision offers such that its revised total ERS Self-Provision capacity is greater than or equal to its proxy ERS Self-Provision Capacity Upper Limit provided by ERCOT.

(5) A QSE with reduced ERS Self-Provision capacity shall notify ERCOT of the ERS Resources whose obligations are reduced and the quantity of the revised obligations. The QSE must provide this information to ERCOT within two Business Days of receiving Notice of the reduced obligation.

(6) If a QSE reduces its ERS commitment according to these procedures, it will not be obligated to pay ERS charges so long as the ERS Self-Provision capacity it delivers is equal to or greater than its final LRS of the total ERS capacity delivered through offers and ERS Self-Provision, as described in paragraph (2) of Section 6.6.11.2, Emergency Response Service Capacity Charge.

(7) A QSE opting for ERS Self-Provision may also offer separate capacity into ERS in the form of a priced offer in the same manner as any other QSE.

(8) The capacity obligation of a self-provided ERS Resource that is designated for renewal opt-in, as described in paragraph (18) of Section 3.14.3.1, Emergency Response Service Procurement, will be fixed at the original awarded MW level for any subsequent ERS Contract Periods in the ERS Standard Contract Term.

**3.14.3.3 Emergency Response Service Provision and Technical Requirements**

(1) If ERCOT deploys ERS, any ERS Resource that is contractually committed to provide the ERS service type deployed during the ERS Time Period that includes all or any part of the first interval of the Sustained Response Period must deploy. If an ERS Resource does not have an obligation for any part of the first interval of the Sustained Response Period, the ERS Resource is not required to deploy at any time during the Sustained Response Period.

(2) For purposes of this paragraph, deployment obligation time is the cumulative time during the Sustained Response Period of an event during which an ERS Resource has an obligation. Deployment obligation time does not include the ramp time. An ERS Resource shall be subject to a maximum of eight hours of cumulative deployment obligation time per ERS Contract Period, except that for ERS Resources that did not exhaust their obligations in a previous ERS Contract Period within the same ERS Standard Contract Term, the maximum deployment obligation time shall be the remaining deployment obligation time from the previous ERS Contract Period as provided by paragraph (18)(b) of Section 3.14.3.1, Emergency Response Service Procurement.

(3) Notwithstanding paragraph (1) above, the following apply:

(a) For a Non-Weather-Sensitive ERS Resource, if an ERS deployment is still in effect when the ERS Resource’s cumulative deployment obligation time equals or exceeds eight hours, the ERS Resource must continue to meet its event performance requirements for the next four hours or until ERCOT releases the ERS Resource, whichever comes first.

(b) For a Weather-Sensitive ERS Resource, the following shall apply:

(i) The maximum number of deployment events during an ERS Standard Contract Term shall be equal to two times the number of months of weather-sensitive obligation in the ERS Standard Contract Term.

(ii) The duration of a Weather-Sensitive ERS Load’s deployment obligation time for a single event shall be a maximum of three hours.

(iii) If an ERS deployment is still in effect when the Weather-Sensitive ERS Resource’s cumulative deployment obligation time equals or exceeds eight hours, the ERS Resource must continue to meet its event performance requirements until the three-hour maximum deployment obligation time for that event is met or ERCOT releases the ERS Load, whichever comes first.

(4) Unless ERCOT has received a notice of unavailability in a format prescribed by ERCOT, ERCOT shall assume that a contracted ERS Resource is fully available to provide ERS.

(5) QSEs and ERS Resources they represent shall meet the following technical requirements:

(a) Each ERS Resource, including each member of an aggregated ERS Resource, must have an ESI ID or Resource ID (RID) and dedicated metering, as defined by ERCOT. An ERS Resource located outside of a competitive service area may use a unique service identifier in lieu of an ESI ID or RID. ERCOT shall analyze 15-minute interval meter data, adjusted for the deemed actual Distribution Loss Factors (DLFs), for each ERS Resource for purposes of offer analysis, availability and performance measurement. ERS Resources behind a NOIE meter point shall arrange, preferably with the NOIE TDSP, to provide ERCOT with 15-minute interval meter data subject to ERCOT’s specifications and approval. ERS Resources behind a Private Use Network’s Settlement Meter point shall provide ERCOT 15-minute interval meter data subject to ERCOT’s specifications and approval. All generators in an ERS Resource must have TDSP metering capable of measuring energy exported to the ERCOT System and TDSP metering capable of measuring energy imported from the ERCOT System. The ERS Resource associated with unique meters in competitive choice areas will be adjusted by the same DLFs as the ESI ID associated with that ERS Resource. The ERS Resource associated with unique meters in NOIE areas will be adjusted based on a NOIE DSP DLF study submitted to ERCOT pursuant to paragraph (6) of Section 13.3, Distribution Losses.

(b) An ERS Resource participating in ERS-10 must be capable of meeting its event performance obligations relevant to its assigned performance evaluation methodology within ten minutes of an ERCOT Dispatch Instruction to its QSE, and must be able to maintain such performance for the entire Sustained Response Period. An ERS Resource participating in ERS-30 must be capable of meeting its event performance obligations relevant to its assigned performance evaluation methodology within 30 minutes of an ERCOT Dispatch Instruction to its QSE, and must be able to maintain such performance for the entire Sustained Response Period. An ERS Resource shall not return to normal operations until released to do so by ERCOT or until the ERS Resource has reached its maximum deployment time, whichever occurs first.

(c) A QSE must be capable of communicating with its ERS Resources in sufficient time to ensure deployment as described in paragraph (b) above.

(d) QSEs shall communicate to ERCOT, in a method prescribed by ERCOT, material changes in the availability status of their ERS Resources.

(e) An ERS Resource deployed for ERS must be able to return to a condition such that it is capable of meeting its ERS performance requirements within ten hours following a release Dispatch Instruction.

(f) ERS Resources and their QSEs are subject to qualification based on ERCOT’s evaluation of their historical meter data and, if applicable, their historic performance in providing other comparable ERCOT services. ERS Resources and their QSEs are subject to testing requirements as described in Section 8.1.3.2, Testing of Emergency Response Service Resources.

(g) ERS Resources are not subject to the modeling, telemetry and COP requirements of other Resources.

(6) The contracted capacity of ERS Resources may not be used to provide Ancillary Services during a contracted ERS Time Period. Nothing herein shall be construed to limit passive (voluntary) Load response, provided the ERS Resource meets its performance and availability requirements, as described in Section 8.1.3.1, Performance Criteria for Emergency Response Service Resources.

(7) QSEs representing ERS Resources must meet the requirements specified in Section 8.1.3.3, Payment Reductions and Suspension of Qualification of Emergency Response Service Resources and/or their Qualified Scheduling Entities.

**3.14.3.4 Emergency Response Service Reporting and Market Communications**

(1) ERCOT shall review the effectiveness and benefits of ERS every 12 months from the start of the program and report its findings to TAC no later than April 15 of each calendar year.

(2) Prior to the start of the first ERS Contract Period in an ERS Standard Contract Term, and no later than the end of the third Business Day following the start of any subsequent ERS Contract Period in an ERS Standard Contract Term, ERCOT shall post on the MIS Public Area the number of MW procured per ERS Time Period, the number and type of ERS Resources selected, and the projected total cost of ERS for that ERS Contract Period.

(3) ERCOT shall post the following documents to the MIS Certified Area for each of the four ERS service types:

(a) ERS Award Notification;

(b) ERS Resources Submission Form – Approved;

(c) ERS Resource Event Performance Summary;

(d) ERS Resource Availability Summary;

(e) ERS Test Portfolio;

(f) ERS Resource Test Results;

(g) ERS Pre-populated Resource Identification Forms;

(h) ERS Resource Group Assignments;

(i) ERS Resource Submission Form – Error Reports;

(j) ERS Preliminary Baseline Review Results;

(k) ERS QSE Portfolio Availability Summary;

(l) ERS QSE Portfolio Event Performance Summary;

(m) ERS Meter Data Error Report; and

(n) ERS QSE-level Payment Details Report.

(4) At least 24 hours before an ERS Standard Contract Term begins, or within 72 hours after the beginning of a new ERS Contract Period within an ERS Standard Contract Term, ERCOT shall provide each affected TDSP with:

(a) A list of ERS Resources and members of aggregated ERS Resources located in the TDSP’s service area that will be participating in ERS during the upcoming ERS Standard Contract Term;

(b) The name of the QSE representing each ERS Resource;

(c) The ERS service type provided by each ERS Resource for each ERS Time Period;

(d) All applicable ESI IDs associated with each ERS Resource; and

(e) The date(s) of the interconnection agreement(s) for each generator in any ERS Generator.

(5) TDSPs shall maintain the confidentiality of the information provided pursuant to paragraph (4) above.

(6) ERCOT shall post to the MIS Public Area the following information for each ERS offer 60 days after the first day of the ERS Standard Contract Term:

(a) The name of the QSE submitting the offer;

(b) For each ERS Time Period, the price and quantity offered, or if the offer is for self-provided ERS, the quantity offered and an indication that the MW will be self-provided; and

(c) The ERS service type.

3.15 Voltage Support

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

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

(3) Each Generation Resource required to provide VSS shall comply with the following Reactive Power Requirements:

(a) An over-excited (lagging or producing) power factor capability of 0.95 or less determined at the generating unit's maximum net power to be supplied to the ERCOT Transmission Grid and the Generation Resource’s set point in the Voltage Profile measured at the POI;

(b) An under-excited (leading or absorbing) power factor capability of 0.95 or less, determined at the generating unit's maximum net power to be supplied to the ERCOT Transmission Grid and the Generation Resource’s set point in the Voltage Profile measured at the POI;

(c) Reactive Power capability shall be available at all MW output levels and may be met through a combination of the Generation Resource’s Unit Reactive Limit (URL), which is the generating unit’s dynamic leading and lagging operating capability, and/or dynamic VAr capable devices. This Reactive Power profile is depicted graphically as a rectangle. For Intermittent Renewable Resources (IRRs), the Reactive Power requirements shall be available at all MW output levels at or above 10% of the IRR’s nameplate capacity. When an IRR is operating below 10% of its nameplate capacity and is unable to support voltage at the POI, ERCOT may require an IRR to disconnect from the ERCOT System for purposes of maintaining reliability; and

(d) As part of the technical Resource testing requirements prior to the Resource Commissioning Date, all Generation Resources must conduct an engineering study, or demonstrate through performance testing, compliance with the Reactive Power capability requirements of this section. Any study or testing results must be accepted by ERCOT prior to the Resource Commissioning Date.

(4) Wind-powered Generation Resources (WGRs) that commenced operation on or after February 17, 2004, and have a signed Standard Generation Interconnection Agreement (SGIA) on or before December 1, 2009 (“Existing Non-Exempt WGRs”), must be capable of producing a defined quantity of Reactive Power to maintain a set point in the Voltage Profile established by ERCOT in accordance with the Reactive Power requirements established in paragraph (3) above, except in the circumstances described in paragraph (a) below.

(a) Existing Non-Exempt WGRs whose current design does not allow them to meet the Reactive Power requirements established in paragraph (3) above must conduct an engineering study using the Summer/Fall 2010 on-peak/off-peak Voltage Profiles, or conduct performance testing to determine their actual Reactive Power capability. Any study or testing results must be accepted by ERCOT. The Reactive Power requirements applicable to these Existing Non-Exempt WGRs will be the greater of: the leading and lagging Reactive Power capabilities established by the Existing Non-Exempt WGR’s engineering study or testing results; or Reactive Power proportional to the real power output of the Existing Non-Exempt WGR (this Reactive Power profile is depicted graphically as a triangle) sufficient to provide an over-excited (lagging) power factor capability of 0.95 or less and an under-excited (leading) power factor capability of 0.95 or less, both determined at the WGR’s set point in the Voltage Profile established by ERCOT, and both measured at the POI.

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

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

(iii) If the Existing Non-Exempt WGR’s engineering study results or testing results indicate that the WGR is not able to provide Reactive Power capability that meets the triangle profile described in paragraph (4)(a) above, then the Existing Non-Exempt WGR will take steps necessary to meet that Reactive Power requirement depicted graphically as a triangle by a date mutually agreed upon by the Existing Non-Exempt WGR and ERCOT. The Existing Non-Exempt WGR may meet the Reactive Power requirement through a combination of the WGR’s URL and/or automatically switchable static VAr capable devices and/or dynamic VAr capable devices. No later than five Business Days after completion of the steps to meet that Reactive Power requirement, the Existing Non-Exempt WGR will update any and all Resource Registration data regarding its Reactive Power and provide written notice to ERCOT that it has completed the steps necessary to meet its Reactive Power requirement.

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

(b) Existing Non-Exempt WGRs whose current design allows them to meet the Reactive Power requirements established in paragraph (3) above (depicted graphically as a rectangle) shall continue to comply with that requirement. ERCOT, with cause, may request that these Existing Non-Exempt WGRs provide further evidence, including an engineering study, or performance testing, to confirm accuracy of Resource Registration data supporting their Reactive Power capability.

(5) Qualified Renewable Generation Resources (as described in Section 14, State of Texas Renewable Energy Credit Trading Program) in operation before February 17, 2004, required to provide VSS and all other Generation Resources required to provide VSS that were in operation prior to September 1, 1999, whose current design does not allow them to meet the Reactive Power requirements established in paragraph (3) above, will be required to maintain a Reactive Power requirement as defined by the Generation Resource’s URL that was submitted to ERCOT and established per the criteria in the ERCOT Operating Guides.

(6) New generating units connected before May 17, 2005, whose owners demonstrate to ERCOT’s satisfaction that design and/or equipment procurement decisions were made prior to February 17, 2004, based upon previous standards, whose design does not allow them to meet the Reactive Power requirements established in paragraph (3) above, will be required to maintain a Reactive Power requirement as defined by the Generation Resource’s URL that was submitted to ERCOT and established per the criteria in the Operating Guides.

(7) For purposes of meeting the Reactive Power requirements in paragraphs (3) through (6) above, multiple generation units including IRRs shall, at a Generation Entity’s option, be treated as a single Generation Resource if the units are connected to the same transmission bus.

(8) Generation Entities may submit to ERCOT specific proposals to meet the Reactive Power requirements established in paragraph (3) above by employing a combination of the URL and added VAr capability, provided that the added VAr capability shall be automatically switchable static and/or dynamic VAr devices. A Generation Resource and TSP may enter into an agreement in which the proposed static VAr devices can be switchable using Supervisory Control and Data Acquisition (SCADA). ERCOT may, at its sole discretion, either approve or deny a specific proposal, provided that in either case, ERCOT shall provide the submitter an explanation of its decision.

(9) A Generation Resource and TSP may enter into an agreement in which the Generation Resource compensates the TSP to provide VSS to meet the Reactive Power requirements of paragraph (3) above in part or in whole. The TSP shall certify to ERCOT that the agreement complies with the Reactive Power requirements of paragraph (3).

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

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

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

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

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

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

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

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

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

3.15.1 ERCOT Responsibilities Related to Voltage Support

(1) ERCOT, in coordination with the TSPs, shall establish, and update as necessary, Voltage Profiles at POI of Generation Resources required to provide VSS to maintain system voltages within established limits.

(2) ERCOT shall communicate to the Qualified Scheduling Entity (QSE) and TSPs the desired voltage at the point of generation interconnection by providing Voltage Profiles.

(3) ERCOT, in coordination with TSPs, shall deploy static Reactive Power Resources as required to continuously maintain dynamic reactive reserves from QSEs, both leading and lagging, adequate to meet ERCOT System requirements.

(4) For any Market Participant’s failure to meet the Reactive Power voltage control requirements of these Protocols, ERCOT shall notify the Market Participant in writing of such failure and, upon a request from the Market Participant, explain whether and why the failure must be corrected.

(5) ERCOT shall notify all affected TSPs of any alternative requirements it approves.

(6) Annually, ERCOT shall review Distribution Service Provider (DSP) power factors using the actual summer Load and power factor information included in the annual Load data request to assess whether DSPs comply with the requirements of this subsection. At times selected by ERCOT, ERCOT shall require manual power factor measurement at substations and POIs that do not have power factor metering. ERCOT shall try to provide DSPs sufficient notice to perform the manual measurements. ERCOT may not request more than four measurements per calendar year for each DSP substation or POI where power factor measurements are not available.

(7) If actual conditions indicate probable non-compliance of TSPs and DSPs with the requirements to provide voltage support, ERCOT shall require power factor measurements at the time of its choice while providing sufficient notice to perform the measurements.

(8) ERCOT shall investigate claims of TSP and DSP alleged non-compliance with Voltage Support requirements. The ERCOT investigator shall advise ERCOT and TSP planning and operating staffs of the results of such investigations.

3.15.2 DSP Responsibilities Related to Voltage Support

(1) Each DSP and Resource Entity within a Private Use Network shall meet the requirements specified in this subsection, or at their option, may meet alternative requirements specifically approved by ERCOT. Such alternative requirements may include requirements for aggregated groups of Facilities.

(a) Sufficient static Reactive Power capability shall be installed by a DSP or a Resource Entity within a Private Use Network not subject to a DSP tariff in substations and on the distribution voltage system to maintain at least a 0.97 lagging power factor for the maximum net active power measured in aggregate on the distribution voltage system. In those cases where a Private Use Network’s power factor is established and governed by a DSP tariff, a Resource Entity within a Private Use Network shall ensure that the Private Use Network meets the requirements as defined and measured in the applicable tariff.

(b) DSP substations whose annual peak Load has exceeded ten MW shall have and maintain Watt/VAr metering sufficient to monitor compliance; otherwise, DSPs are not required to install additional metering to determine compliance.

(c) All DSPs shall report any changes in their estimated net impact on ERCOT as part of the annual Load data assessment.

(d) As part of the annual Load data assessment, all Resource Entities owning Generation Resources shall provide an annual estimate of the highest potential affiliated MW and MVAr Load (including any Load netted with the generation output) and the highest potential MW and MVAr generation that could be experienced at the POI to the ERCOT Transmission Grid, based on the current configuration (and the projected configuration if the configuration is going to change during the year) of the Generation Resource and any affiliated Loads.

3.15.3 Generation Resource Requirements Related to Voltage Support

(1) Generation Resources required to provide VSS shall have and maintain Reactive Power capability at least equal to the Reactive Power capability requirements specified in these Protocols and the ERCOT Operating Guides.

(2) Generation Resources providing VSS shall be compliant with the ERCOT Operating Guides for response to transient voltage disturbance.

(3) Generation Resources providing VSS must meet technical requirements specified in Section 8.1.1.1, Ancillary Service Qualification and Testing, and the performance standards specified in Section 8.1.1, QSE Ancillary Service Performance Standards.

(4) Each Generation Resource providing VSS shall operate with the unit’s Automatic Voltage Regulator (AVR) in the automatic voltage control mode unless specifically directed to operate in manual mode by ERCOT, or when the unit is telemetering its Resource Status as STARTUP, SHUTDOWN, or ONTEST, or the QSE determines a need to operate in manual mode in the event of an Emergency Condition at the generating plant.

(5) Each Generation Resource providing VSS shall maintain the Voltage Set Point established by ERCOT, the interconnecting TSP, or the TSP’s agent, subject to the Generation Resource’s operating characteristic limits, voltage limits, and within tolerances identified in paragraph (4) of Operating Guide Section 2.7.3.5, Resource Entity Responsibilities and Generation Resource Requirements.

(6) The reactive capability required must be maintained at all times that the Generation Resource is On-Line.

(7) Each QSE shall send to ERCOT, via telemetry, the AVR and Power System Stabilizer (PSS) status for each of its Generation Resources providing VSS. For AVRs, an “On” status will indicate the AVR is on and set to regulate the Resource’s terminal voltage in the voltage control mode, and an “Off” status will indicate the AVR is off or in a manual mode. For PSS, an “On” status will indicate the service is enabled and ready for service, and an “Off” status will indicate it is off or out of service. Each QSE shall monitor the status of its Generation Resources’ regulators and stabilizers, and shall report status changes to ERCOT.

(8) Each Resource Entity shall provide information related to the tuning parameters, local or inter-area, of any PSS installed at a Generation Resource.

3.16 Standards for Determining Ancillary Service Quantities

(1) ERCOT shall comply with the requirements for determining Ancillary Service quantities as specified in these Protocols and the ERCOT Operating Guides.

(2) ERCOT shall, at least annually, determine with supporting data, the methodology for determining the quantity requirements for each Ancillary Service needed for reliability, including the minimum capacity required from Resources providing Primary Frequency Response to provide Responsive Reserve (RRS) calculated on a monthly basis, the maximum amount (MW) of Regulation Up Service (Reg-Up) that can be provided by Resources providing Fast Responding Regulation Up Service (FRRS-Up), and the maximum amount (MW) of Regulation Down Service (Reg-Down) that can be provided by Resources providing Fast Responding Regulation Down Service (FRRS-Down). The minimum capacity required from Resources providing Primary Frequency Response shall not be less than 1,150 MW.

(3) The ERCOT Board shall review and approve ERCOT's methodology for determining the minimum Ancillary Service requirements, the minimum capacity required from Resources providing Primary Frequency Response to provide RRS, and the maximum amount of Reg-Up and Reg-Down that can be provided by Resources providing FRRS-Up and FRRS-Down.

(4) If ERCOT determines a need for additional Ancillary Service Resources under these Protocols or the ERCOT Operating Guides, after an Ancillary Service Plan for a specified day has been posted, ERCOT shall inform the market by posting notice on the Market Information System (MIS) Public Area, of ERCOT’s intent to procure additional Ancillary Service Resources under Section 6.4.9.2, Supplemental Ancillary Services Market. ERCOT shall post the reliability reason for the increase in service requirements.

(5) Monthly, ERCOT shall determine and post on the MIS Secure Area a minimum capacity required from Resources providing RRS using Primary Frequency Response. The remaining capacity required for RRS may be supplied by all Resources qualified to provide RRS including Load Resources on high-set under-frequency relays, provided that RRS from these Load Resources shall be limited to 60% of the total ERCOT RRS requirement. ERCOT may increase the minimum capacity required from Resources providing RRS using Primary Frequency Response if it believes that the current posted quantity will have a negative impact on reliability or if it would require additional Regulation Service to be deployed.

(6) The amount of RRS that a Qualified Scheduling Entity (QSE) can self-arrange using a Load Resource excluding Controllable Load Resources is limited to its Load Ratio Share (LRS) of the capacity allowed to be provided by Resources not providing RRS using Primary Frequency Response established in paragraph (5) above, provided that RRS from these Load Resources shall be limited to 60% of the total ERCOT RRS requirement.

(7) However, a QSE may bid more of the Load Resource above the percentage limit established by ERCOT for sale of RRS to other Market Participants. The total amount of RRS Service using the Load Resource excluding Controllable Load Resources procured by ERCOT is also limited to the capacity established in paragraph (5) above, up to the lesser of the 60% limit or the limit established by ERCOT in paragraph (5) above.

(8) The maximum MW amount of capacity from Resources providing FRRS-Up is limited to 65 MW. ERCOT may reduce this limit if it believes that this amount will have a negative impact on reliability or if this limit would require additional Regulation Service to be deployed.

(9) The maximum MW amount of capacity from Resources providing FRRS-Down is limited to 35 MW. ERCOT may reduce this limit if it believes that this amount will have a negative impact on reliability or if this limit would require additional Regulation Service to be deployed.

(10) Resources can only provide FRRS-Up or FRRS-Down if awarded Regulation Service in the Day-Ahead Market (DAM) for that particular Resource, up to the awarded quantity.

3.17 Ancillary Service Capacity Products

3.17.1 Regulation Service

(1) Regulation Up Service (Reg-Up) is a service that provides capacity that can respond to signals from ERCOT within five seconds to respond to changes from scheduled system frequency. The amount of Reg-Up capacity is the amount of capacity available from a Resource that may be called on to change output as necessary to maintain proper system frequency. A Generation Resource providing Reg-Up must be able to increase energy output when deployed and decrease energy output when recalled. A Load Resource providing Reg-Up must be able to decrease Load when deployed and increase Load when recalled. Fast Responding Regulation Up Service (FRRS-Up) is a subset of Reg-Up Service in which the participating Resource provides Reg-Up capacity to ERCOT within 60 cycles of either its receipt of an ERCOT Dispatch Instruction or the detection of a trigger frequency independent of an ERCOT Dispatch Instruction. ERCOT dispatches Reg-Up by a Load Frequency Control (LFC) signal. The LFC signal for FRRS-Up is separate from the LFC signal for other Reg-Up.

(2) Regulation Down Service (Reg-Down) is a service that provides capacity that can respond to signals from ERCOT within five seconds to respond to changes from scheduled system frequency. The amount of Reg-Down capacity is the amount of capacity available from a Resource that may be called on to change output as necessary to maintain proper system frequency. A Generation Resource providing Reg-Down must be able to decrease energy output when deployed and increase energy output when recalled. A Load Resource providing Reg-Down must be able to increase Load when deployed and decrease Load when recalled. Fast Responding Regulation Down Service (FRRS-Down) is a subset of Reg-Down Service in which a participating Resource provides Reg-Down capacity to ERCOT within 60 cycles of either its receipt of an ERCOT Dispatch Instruction or the detection of a trigger frequency independent of an ERCOT Dispatch Instruction. ERCOT dispatches Reg-Down by an LFC signal. The LFC signal for FRRS-Down is separate from the LFC signal for other Reg-Down.

3.17.2 Responsive Reserve Service

(1) Responsive Reserve (RRS) is a service used to restore or maintain the frequency of the ERCOT System:

(a) In response to, or to prevent, significant frequency deviations;

(b) As backup Regulation Service; and

(c) By providing energy during an Energy Emergency Alert (EEA).

(2) RRS may be provided through one or more of the following means:

(a) By using frequency-dependent response from On-Line Resources as prescribed in the Operating Guides to help restore the frequency within the first few seconds of an event that causes a significant frequency deviation in the ERCOT System; and

(b) Either manually or by using a four-second signal to provide energy on deployment by ERCOT.

(3) RRS may be used to provide energy during the implementation of an EEA. Under the EEA, RRS provides generation capacity, capacity from Controllable Load Resources or interruptible Load available for deployment on ten minutes’ notice.

(4) RRS may be provided by:

(a) Unloaded, On-Line Generation Resource capacity;

(b) Load Resources controlled by high-set, under-frequency relays;

(c) Controllable Load Resources; and

(d) Hydro RRS as defined in the Operating Guides.

3.17.3 Non-Spinning Reserve Service

(1) Non-Spinning Reserve (Non-Spin) Service is provided by using:

(a) Generation Resources, whether On-Line or Off-Line, capable of:

(i) Being synchronized and ramped to a specified output level within 30 minutes; and

(ii) Running at a specified output level for at least one hour; or

(b) Controllable Load Resources qualified for Dispatch by Security-Constrained Economic Dispatch (SCED) and capable of:

(i) Ramping to an ERCOT-instructed consumption level within 30 minutes; and

(ii) Consuming at the ERCOT-instructed level for at least one hour.

(2) The Non-Spin may be deployed by ERCOT to increase available reserves in Real-Time Operations.

3.18 Resource Limits in Providing Ancillary Service

(1) For both Generation Resources and Load Resources the High Sustained Limit (HSL) must be greater than or equal to the Low Sustained Limit (LSL) and the sum of the Resource-specific designation of capacity to provide Responsive Reserve (RRS), Regulation Up (Reg-Up), Regulation Down (Reg-Down), and Non-Spinning Reserve (Non-Spin).

(2) For Non-Spin, the amount of Non-Spin provided must be less than or equal to the HSL for Off-Line Generation Resources.

(3) For RRS Service:

(a) The full amount of RRS provided from a Generation Resource must be less than or equal to 20% of thermal unit HSL for an Ancillary Service Offer, and must be less than or equal to ten times the Emergency Ramp Rate, and must be frequency responsive;

(b) Hydro Generation Resources operating in the synchronous condenser fast-response mode may provide RRS up to the hydro Generation Resource’s proven 20-second response capability (which may be 100% of the HSL). The initiation setting of the automatic under-frequency relay setting shall not be lower than 59.80 Hz;

(c) For any hydro Generation Resource with a 5% droop setting operating as a generator, the amount of RRS provided may never be more than 20% of the HSL; and

(d) The amount of RRS provided from a Load Resource must be less than or equal to the HSL minus the sum of the LSL, Reg-Up Resource Responsibility, Reg-Down Resource Responsibility, and Non-Spin Resource Responsibility.

3.19 Constraint Competitiveness Tests

3.19.1 Constraint Competitiveness Test Definitions

(1) The Constraint Competitiveness Test (CCT) checks the competitiveness of a constraint by evaluating each Market Participant’s ability to exercise market power by physical or economic withholding. The CCT for a constrained Transmission Element evaluates whether there is sufficient competition to resolve the constraint on the import side by calculating the Element Competitiveness Index (ECI) on the import side of the constraint and by determining whether a single Entity is needed to resolve the constraint.

(2) The competitiveness of a constraint is tested both on a long-term basis and before each Security-Constrained Economic Dispatch (SCED) execution.

(3) The “Available Capacity for a Resource” is defined as follows:

(a) For Generation Resources, including Switchable Generation Resources, but excluding Intermittent Renewable Resources (IRRs):

(i) Long-Term CCT - the Seasonal net max sustainable rating, as registered with ERCOT.

(ii) SCED CCT - the telemetered High Sustained Limit (HSL) for Resources with telemetered Resource Status as specified in paragraph (5)(b)(i) of Section 3.9.1, Current Operating Plan (COP) Criteria, and zero for all other Resources.

(b) For IRRs:

(i) Long-Term CCT - the Seasonal net max sustainable rating, as registered with ERCOT, on the export side and zero MW on the import side.

(ii) SCED CCT - the telemetered HSL for Resources with telemetered Resource Status as specified in paragraph (5)(b)(i) of Section 3.9.1 and zero for all other Resources.

(c) For the Direct Current Tie (DC Tie) lines, the full import capability on the export side and zero MW on the import side for all CCTs.

(4) “Managed Capacity for an Entity” is a Resource or Split Generation Resource for which the Entity or its Affiliates has the decision-making authority over how the Resource or Split Generation Resource is offered or scheduled (e.g., Output Schedules), in accordance with subsection (d) of P.U.C. Subst. R. 25.502, Pricing Safeguards in Markets Operated by the Electric Reliability Council of Texas. Each Resource Entity that owns a Resource shall submit a declaration to ERCOT, using Section 23, Form C, Managed Capacity Declaration, as to which Entity has the decision-making authority for 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 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. Upon ERCOT’s request, each Resource Entity that owns a Resource shall provide ERCOT with sufficient information or documentation to verify control of the Resource. ERCOT shall apply decision-making authority to Managed Capacity for an Entity effective the first Operating Hour of the Operating Day 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.

(5) Shift Factors of all Electrical Buses are computed relative to the distributed load reference Bus.

(a) For voltage, stability, and thermal-limited constraints, as well as interfaces represented by thermal limits, the Shift Factors should be computed with no other contingencies removed from the electrical network.

(b) For contingency-limited constraints, the Shift Factors used should be computed with the contingencies removed from the electrical network.

(6) As part of the Long-Term and SCED CCT processes described below, there are several thresholds used in determining the competitive designation of a constraint and the Resources for which mitigation will be applied in SCED Step 2, as described in Section 6.5.7.3, Security Constrained Economic Dispatch. These thresholds are defined as follows:

|  |  |  |
| --- | --- | --- |
| **Threshold** | **Definition** | **Value** |
| SFP1 | Minimum Shift Factor threshold for determining which Managed Capacity for an Entity to include in the ECI calculation | 2% |
| ECIT1 | Maximum competitive threshold for ECI on the import side of a constraint for the Long-Term CCT process | 2000 |
| SFP2 | Minimum Shift Factor threshold for a constraint to be eligible to be a Competitive Constraint as part of the Long-Term CCT process | 2% |
| ECIT2 | Maximum competitive threshold for ECI on the import side of a constraint for the SCED CCT process | 2300 |
| SFP3 | Minimum Shift Factor threshold for a constraint to be eligible to be a Competitive Constraint as part of the SCED CCT process | 2% |
| DMEECP | Threshold for the ECI Effective Capacity for an Entity or its Affiliates to determine if their Managed Capacity for an Entity is eligible to be mitigated as part of SCED Step 2 | 10% |
| SFP4 | Minimum Shift Factor threshold below which a Resource will not have mitigation applied in SCED Step 2 | 2% |

3.19.2 Element Competitiveness Index Calculation

(1) To compute the ECI on the import side, first determine the “ECI Effective Capacity” available to resolve the constraint. The ECI Effective Capacity that each Entity contributes to resolve the constraint on the import side is determined by taking, for each Managed Capacity for an Entity having negative Shift Factors with absolute values greater than the minimum of one-third of the highest absolute value of any Resource Shift Factor with a negative value and SFP1, the sum of the products of (a) the Available Capacity for a Resource and (b) the square of the Shift Factor of that Resource to the constraint.

(2) ERCOT will determine the ECI on the import of the constraint, as follows:

(a) Determine the total ECI Effective Capacity by each Entity and its Affiliates on the import side.

(b) Determine the percentage of ECI Effective Capacity by each Entity and its Affiliates on the import side by taking each Entity and its Affiliates’ ECI Effective Capacity and dividing by the total ECI Effective Capacity on the import side.

(c) The ECI on the import side is equal to the sum of the squares of the percentages of ECI Effective Capacity for each Entity and its Affiliates on the import side.

3.19.3 Long-Term Constraint Competitiveness Test

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

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

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

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

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

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

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

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

3.19.4 Security-Constrained Economic Dispatch Constraint Competitiveness Test

(1) The SCED CCT uses current system conditions to evaluate the competitiveness of a constraint.

(2) Before each SCED execution, CCT is performed for all active constraints in SCED. The SCED CCT shall classify a constraint as competitive for the current SCED execution if the constraint meets all of the following conditions:

(a) The ECI is less than ECIT2 on the import side;

(b) The constraint can be resolved by eliminating all Available Capacity for a Resource on the import side, except nuclear capacity and minimum-energy amounts of coal and lignite capacity, that is Managed Capacity for an Entity or its Affiliates. If the constraint cannot be resolved, then the Entity and its Affiliates will be marked as the pivotal player for resolving the constraint;

(c) There are negative Shift Factors corresponding to Electrical Buses with Available Capacity for a Resource that have an absolute value greater than or equal to SFP3; and

(d) The constraint was not designated as non-competitive by a previous SCED CCT execution within the current Operating Hour.

(3) Any constraint that is analyzed and is not designated as a Competitive Constraint under the conditions outlined in paragraph (2) above shall be designated as a Non-Competitive Constraint by the SCED CCT.

(4) A constraint that is determined to be a Non-Competitive Constraint by the SCED CCT within an Operating Hour will not be re-evaluated for its competitiveness status for the remainder of that Operating Hour. However, the SCED CCT will reevaluate the percentage of the ECI Effective Capacity on the import side for each decision-making authority and whether the decision-making authority is a pivotal player for the constraint. SCED will re-evaluate the competitiveness of the Non-Competitive Constraint starting with the first SCED interval of the next Operating Hour if the constraint remains active in SCED.

(5) The Independent Market Monitor (IMM) may designate any constraint as a Competitive Constraint or a Non-Competitive Constraint.  ERCOT shall provide notice describing any such designation by the IMM.  The notice shall include an effective date, justification for the constraint designation by the IMM and the duration for which the IMM designation will be applied. Any such designation from the IMM shall override the competitiveness status determined by the SCED CCT for the dates for which the IMM override is effective.

(6) Each hour, ERCOT shall post on the MIS Public Area whether each binding constraint was designated as a Competitive Constraint or as a Non-Competitive Constraint for each of the SCED executions during the previous Operating Hour.

(7) Mitigation will be applied to a Resource in the SCED Step 2, as described in Section 6.5.7.3, Security Constrained Economic Dispatch, when all of the following conditions are met:

(a) A constraint has been determined to be a Non-Competitive Constraint by either the SCED CCT or the IMM;

(b) The Entity with decision-making authority for the Resource is either identified as a pivotal player for the constraint as described in paragraph (4) above or has a percentage of ECI Effective Capacity on the import side for the constraint greater than DMEECP; and

(c) The Resource has a Shift Factor on the import side of the constraint with an absolute value greater than SFP4;

(8) Once mitigation has been applied to a Resource for a SCED interval, it shall remain applied for the remainder of the Operating Hour regardless of the conditions listed in paragraph (7) above.

3.20 Identification of Chronic Congestion

(1) A constraint that has been active or binding on three or more Operating Days within a rolling 30-day period shall be considered to be experiencing chronic congestion.

3.20.1 Evaluation of Chronic Congestion

(1) ERCOT shall evaluate chronic congestion on an ongoing basis and shall provide the results of its evaluation to the appropriate Technical Advisory Committee (TAC) subcommittee(s). This evaluation shall include, but is not limited to the following:

(a) Identification of chronic congestion; and

(b) Verification of the topology and Transmission Facilities Ratings of the Network Operations Model and Updated Network Model.

3.20.2 Topology and Model Verification

(1) For constraints meeting the criteria in Section 3.20.1, Evaluation of Chronic Congestion, ERCOT shall discuss and validate with the appropriate Transmission Service Provider (TSP) and Resource Entity that the data from the Network Operations Model and Updated Network Model are correct, including the Ratings of the Transmission Facility causing an active or binding transmission constraint. When analysis differs between ERCOT and a TSP or Resource Entity, ERCOT shall verify the configuration of the ERCOT Transmission Grid matches that of the model in use by the TSP or Resource Entity.

(2) If ERCOT determines that the Network Operations Model, the Updated Network Model, or the configuration of the Transmission Facility is inaccurate, ERCOT shall notify the owner of the Transmission Facility of the need to update the Ratings as required by paragraph (3) of Section 3.10, Network Operations Modeling and Telemetry.

(3) If ERCOT determines the Network Operations Model and the Updated Network Model are accurate, ERCOT shall update the planning model and study assumptions as appropriate.

3.21 Submission of Emergency Operations Plans, Weatherization Plans, and Declarations of Summer and Winter Weather Preparedness

(1) Each Resource Entity shall provide ERCOT a complete copy of the emergency operations plan for each Generation Resource under the Resource Entity’s control. For any jointly owned Generation Resource, the emergency operations plan shall be submitted by the Master Owner designated in the Resource Registration process. Each Resource Entity shall provide ERCOT with any updated versions of the emergency operations plan by June 1 for any updates made between November 1 and April 30, and by December 1 for any updates made between May 1 through October 31. Resource Entities shall submit all plans and updates electronically. This paragraph does not apply to any currently Mothballed Generation Resource.

(2) For each emergency operations plan submitted, a Resource Entity shall either specifically designate which portions of the plan address weatherization, or shall separately submit a weatherization plan. At a minimum, the emergency operations plan or weatherization plan, as applicable, shall include a description of the Generation Resource’s practices and procedures undertaken in preparation for winter and summer weather and during specific occurrences of extreme weather. If a weatherization plan is submitted separately, the Resource Entity shall provide ERCOT with any updated versions of this weatherization plan by June 1 for any updates made between November 1 and April 30, and by December 1 for any updates made between May 1 through October 31. Resource Entities shall submit all such plans and updates electronically. Notwithstanding the foregoing, for any Generation Resource for which ERCOT has expressed an intent to conduct a site visit to evaluate weather preparedness, a Resource Entity shall submit to ERCOT, within three Business Days of ERCOT’s request, its most recent weatherization plan or a listing of the portions of its most recent emergency operations plan that address weatherization. Any plan or other information provided in response to an ERCOT request does not fulfill the Resource Entity’s obligation to submit that plan or information to ERCOT as otherwise required by this paragraph.

(3) No earlier than November 1 and no later than December 1 of each year, each Resource Entity shall submit the declaration in Section 22, Attachment K, Declaration of Completion of Generation Resource Weatherization Preparations, to ERCOT stating that, at the time of submission, each Generation Resource under the Resource Entity’s control has completed or will complete all weather preparations required by the weatherization plan for equipment critical to the reliable operation of the Generation Resource during the winter time period (December through February). If the work on the equipment that is critical to the reliable operation of the Generation Resource is not complete at the time of filing the declaration, the Resource Entity shall provide a list and schedule of remaining work to be completed. The declaration shall be executed by an officer or executive with authority to bind the Resource Entity. This declaration shall not apply to any Generation Resource for any part of the above designated winter time period for which the Resource Entity expects the Generation Resource to be mothballed, and a Resource Entity is not required to submit a declaration for any Generation Resource that is expected to be mothballed for the entire winter time period. However, if a Generation Resource was not included on the declaration because it was mothballed at the time the declaration was submitted and was not intended to be operational during the winter time period, a Resource Entity shall provide the declaration for that Generation Resource prior to changing its status from mothballed to operational during the winter time period.

(4) No earlier than May 1 and no later than June 1 of each year, each Resource Entity shall submit the declaration in Section 22, Attachment K, to ERCOT stating that, at the time of submission, each Generation Resource under the Resource Entity’s control has completed or will complete all weather preparations required by the weatherization plan for equipment critical to the reliable operation of the Generation Resource during the summer time period (June through September). If the work on the equipment that is critical to the reliable operation of the Generation Resource is not complete at the time of filing the declaration, the Resource Entity shall provide a list and schedule of remaining work to be completed. The declaration shall be executed by an officer or executive with authority to bind the Resource Entity. This declaration shall not apply to any Generation Resource for any part of the above designated summer time period for which the Resource Entity expects the Generation Resource to be mothballed, and a Resource Entity is not required to submit a declaration for any Generation Resource that is expected to be mothballed for the entire summer time period designated above. However, if a Generation Resource was not included on the declaration because it was mothballed at the time the declaration was submitted and was not intended to be operational during the summer time period, a Resource Entity shall provide the declaration for that Generation Resource prior to changing its status from mothballed to operational during the summer time period.

(5) On or before January 15 each year, ERCOT shall report to the Public Utility Commission of Texas (PUCT) the names of Resource Entities failing to provide the declaration required by paragraph (3) above.

(6) On or before July 15 each year, ERCOT shall report to the PUCT the names of Resource Entities failing to provide the declaration required by paragraph (4) above.

3.22 Subsynchronous Resonance

(1) All series capacitors shall have automatic Subsynchronous Resonance (SSR) protective relays installed and shall have remote bypass capability.  The SSR protective relays shall remain in-service when the series capacitors are in-service.

3.22.1 Subsynchronous Resonance Vulnerability Assessment

(1) In the SSR vulnerability assessment, each transmission circuit is considered as a single Outage. A common tower Outage of two circuits or the Outage of a double-circuit transmission line will be considered as two transmission Outages.

**3.22.1.1 Existing Generation Resource Assessment**

(1) ERCOT shall perform a one-time SSR vulnerability assessment on all existing Generation Resources as described in paragraphs (a) through (f) below. For the purposes of this Section, a Generation Resource is considered an existing Generation Resource if it satisfies Planning Guide Section 6.9, Addition of Proposed Generation to the Planning Models, on or before August 12, 2013.

(a) ERCOT shall perform a topology-check on all existing Generation Resources.

(b) If during the topology-check ERCOT determines that an existing Generation Resource will become radial to a series capacitors(s) in the event of less than 14 concurrent transmission Outages, ERCOT shall perform a frequency scan assessment in accordance with Section 3.22.2, Subsynchronous Resonance Vulnerability Assessment Criteria, and will provide the frequency scan assessment results to the affected Resource Entity.

(c) If the frequency scan assessment described in paragraph (b) above indicates potential SSR vulnerability, the Transmission Service Provider(s) (TSP(s)) that owns the affected series capacitor(s), in coordination with the interconnecting TSP, shall perform a detailed SSR analysis in accordance with Section 3.22.2 to determine SSR vulnerability, unless ERCOT, in consultation with and in agreement with of the affected TSP(s) and the affected Resource Entity, determines the frequency scan assessment is sufficient to determine the SSR vulnerability.

(d) If the SSR study performed in accordance with paragraph (b) and/or (c) above indicates that an existing Generation Resource is vulnerable to SSR in the event of four or less concurrent transmission Outages, the TSP(s) that owns the affected series capacitor(s) shall coordinate with the interconnecting TSP, ERCOT, and the affected Resource Entity to develop and implement SSR Mitigation on the ERCOT transmission system.

(e) If the SSR study performed in accordance with paragraph (b) and/or (c) above indicates that an existing Generation Resource is vulnerable to SSR in the event of five or six concurrent transmission Outages, ERCOT shall implement SSR monitoring in accordance with Section 3.22.3, Subsynchronous Resonance Monitoring.

(f) The Resource Entity shall provide sufficient model data to ERCOT within 60 days of receipt of the data request. ERCOT, at its sole discretion, may extend the response deadline.

**3.22.1.2 Generation Resource Interconnection Assessment**

(1) In the security screening study for a Generation Resource Interconnection or Change Request, ERCOT will perform a topology-check and determine if the Generation Resource will become radial to a series capacitors(s) in the event of less than 14 concurrent transmission Outages.

(2) If ERCOT identifies that a Generation Resource will become radial to a series capacitor(s) in the event of less than 14 concurrent transmission Outages, the interconnecting TSP shall perform an SSR study including frequency scan assessment and/or detailed SSR assessment for the Interconnecting Entity (IE) in accordance with Section 3.22.2, Subsynchronous Resonance Vulnerability Assessment Criteria, to determine SSR vulnerability. The SSR study shall determine which system configurations create vulnerability to SSR. Alternatively, if the IE can demonstrate to ERCOT’s and the interconnecting TSP’s satisfaction that the Generation Resource is not vulnerable to SSR, then the interconnecting TSP is not required to perform the SSR study.

(3) If the SSR study performed in accordance with paragraph (2) above indicates that the Generation Resource is vulnerable to SSR in the event of four or less concurrent transmission Outages, the IE shall develop an SSR Mitigation plan and provide it to ERCOT prior to submission of the Initial Synchronization request. ERCOT shall respond with its acceptance or rejection of the plan within 30 days of receipt. The IE shall implement the ERCOT-approved SSR Mitigation prior to Initial Synchronization.

(a) If the SSR study performed in accordance with paragraph (2) above indicates that the Generation Resource is vulnerable to SSR in the event of four concurrent transmission Outages, the IE may install SSR Protection in lieu of SSR Mitigation, as required by paragraph (3) above, if:

(i) The Generation Resource satisfied Planning Guide Section 6.9, Addition of Proposed Generation to the Planning Models, between August 12, 2013 and March 20, 2015;

(ii) The SSR Protection is approved by ERCOT; and

(iii) The Generation Resource installs the ERCOT-approved SSR Protection prior to Initial Synchronization.

(4) If the SSR study performed in accordance with paragraph (2) above indicates that the Generation Resource is vulnerable to SSR in the event of five or six concurrent transmission Outages, ERCOT shall implement SSR monitoring for the IE prior to Initial Synchronization in accordance with Section 3.22.3, Subsynchronous Resonance Monitoring.

**3.22.1.3 Transmission Project Assessment**

(1) For any proposed Transmission Facilities connecting to or operating at 345 kV, the TSP shall perform an SSR vulnerability assessment, including a topology-check and/or frequency scan assessment in accordance with Section 3.22.2, Subsynchronous Resonance Vulnerability Assessment Criteria. The TSP shall include a summary of the results of this assessment in the project submission to the Regional Planning Group (RPG) pursuant to Section 3.11.4, Regional Planning Group Project Review Process. For Tier 4 projects that include Transmission Facilities connecting to or operating at 345 kV, the TSP shall provide the SSR assessment for ERCOT’s review. For the purposes of this Section, a Generation Resource is considered an existing Generation Resource if it satisfies Planning Guide Section 6.9 at the time the Transmission Facilities are proposed.

(2) If while performing the independent review of a transmission project, ERCOT determines that the transmission project may cause an existing Generation Resource or a Generation Resource satisfying Planning Guide Section 6.9 at the time the transmission project is proposed to become vulnerable to SSR, ERCOT shall perform an SSR vulnerability assessment, including topology-check and frequency scan in accordance with Section 3.22.2 if such an assessment was not included in the project submission. ERCOT shall include a summary of the results of this assessment in the independent review.

(3) If the frequency scan assessment in paragraphs (1) or (2) above indicates potential SSR vulnerability in accordance with Section 3.22.2, the TSP(s) that owns the affected series capacitor(s), in coordination with the TSP proposing the Transmission Facilities, shall perform a detailed SSR assessment to confirm or refute the SSR vulnerability.

(4) Past SSR assessments may be used to determine the SSR vulnerability of a Generation Resource if ERCOT, in consultation with the affected TSPs, determines the results of the past SSR assessments are still valid.

(5) If the SSR study confirms a Generation Resource is vulnerable to SSR in the event of four or less concurrent transmission Outages, the TSP that owns the affected series capacitor(s) shall coordinate with ERCOT, the affected Resource Entity, and affected TSPs to develop and implement SSR Mitigation on the ERCOT transmission system. The SSR Mitigation shall be developed prior to RPG acceptance, if required, and implemented prior to the latter of the energization of the transmission project or the Initial Synchronization of the Generation Resource.

(6) If the SSR study confirms a Generation Resource is vulnerable to SSR in the event of five or six concurrent transmission Outages, ERCOT shall implement SSR monitoring in accordance with Section 3.22.3, Subsynchronous Resonance Monitoring, prior to the latter of the energization of the transmission project or the Initial Synchronization of the Generation Resource.

(7) The Resource Entity shall provide sufficient model data to ERCOT within 60 days of receipt of the data request. ERCOT, at its sole discretion, may extend the response deadline.

**3.22.1.4 Annual SSR Review**

(1) ERCOT shall perform an SSR review annually. The annual review shall include the following elements:

(a) The annual review shall include a topology-check applying the system network topology that is consistent with a year 3 Steady State Working Group (SSWG) base case developed in accordance with Planning Guide Section 6.1, Steady-State Model Development. ERCOT shall post the SSR annual topology-check report to the Market Information System (MIS) Secure Area by May 31 of each year.

(b) If ERCOT identifies that a Generation Resource will become radial to series capacitors(s) in the event of less than 14 concurrent transmission Outages, ERCOT shall perform a frequency scan assessment in accordance with Section 3.22.2, Subsynchronous Resonance Vulnerability Assessment Criteria. ERCOT shall prepare a report to summarize the results of the frequency scan assessment and provide it to the Resource Entity and the affected TSP.

(i) If the frequency scan assessment described in paragraph (b) above shows the Generation Resource has potential SSR vulnerability in the event of six or fewer concurrent transmission Outages, the TSP(s) that owns the affected series capacitor compensated Transmission Element in coordination with the interconnecting TSP shall perform a detailed SSR assessment to confirm or refute the SSR vulnerability.

(ii) Past SSR assessments may be used to determine the SSR vulnerability of a Generation Resource if ERCOT, in consultation with the affected TSPs, determines the results of the past SSR assessments are still valid.

(iii) If the SSR study confirms the Generation Resource is vulnerable to SSR in the event of four or less concurrent transmission Outages, the TSP that owns the affected series capacitor compensated Transmission Element shall coordinate with ERCOT, the affected Resource Entity, and affected TSPs to develop and install SSR Mitigation on the ERCOT transmission system. The SSR Mitigation shall be developed, if required, and implemented prior to the latter of the energization of the transmission project or the Initial Synchronization of the Generation Resource.

(iv) If the SSR study confirms the Generation Resource is vulnerable to SSR in the event of five or six concurrent transmission Outages, ERCOT shall implement SSR monitoring in accordance with Section 3.22.3, Subsynchronous Resonance Monitoring, prior to the latter of energization of the transmission project or the Initial Synchronization of the Generation Resource.

(v) The Resource Entity shall provide sufficient model data to ERCOT within 60 days of receipt of the data request. ERCOT, in its sole discretion, may extend the response deadline.

3.22.2 Subsynchronous Resonance Vulnerability Assessment Criteria

(1) A Generation Resource is considered to be potentially vulnerable to SSR in the topology-check if a Generation Resource will become radial to a series capacitors(s) in the event of less than 14 concurrent transmission Outages. A frequency scan assessment and/or a detailed SSR assessment shall be required to screen for system conditions causing potential SSR vulnerability.

(2) In determining whether a Generation Resource is considered to be potentially vulnerable to SSR in the frequency scan assessment results, the following criteria shall be considered:

(a) Induction Generator Effect (IGE) and Subsynchronous Control Interaction (SSCI):

(i) When considering the total impedance of the generator and the applicable part of the ERCOT System, if the total resistance is negative at a reactance crossover of zero Ohms from negative to positive with increasing frequency, then the generator is considered to be potentially vulnerable to IGE/SSCI;

(b) Torsional Interaction:

(i) If the sum of the electrical damping (De) plus the mechanical damping (Dm) results in a negative value then the generator is potentially vulnerable to Torsional Interaction. Dm at +/- 1 Hz of the modal frequency may be utilized to compare to De; and

(c) Torque Amplification:

(i) When considering the total impedance of the generator and the ERCOT system, if a 5% or greater reactance dip, or a reactance crossover of zero Ohms from negative to positive with increasing frequency, occurs within a +/- 3 Hz complement of the modal frequency, then the generator is considered to be potentially vulnerable to Torque Amplification. The percentage of a reactance dip is on the basis of the reactance maximum at the first inflection point of the dip where the reactance begins to decrease with increasing frequency.

(3) The detailed SSR assessment shall include an electromagnetic transient program analysis or similar analysis. A Generation Resource is considered to be vulnerable to SSR if any of the following criteria are met:

(a) The SSR vulnerability results in more than 50% of fatigue life expenditure over the expected lifetime of the unit;

(i) If the fatigue life expenditure is not available, the highest torsional torque caused by SSR is more than 110% of the torque experienced during a transmission fault with the series capacitors bypassed;

(b) The oscillation, if occurred, is not damped; or

(c) The oscillation, if occurred, results in disconnection of any transmission and generation facilities.

3.22.3 Subsynchronous Resonance Monitoring

(1) For purposes of SSR monitoring, a common tower Outage loss of a double-circuit transmission line consisting of two circuits sharing a tower for 0.5 miles or greater is considered as one contingency.

(2) ERCOT’s responsibilities for SSR monitoring shall consist of the following activities if a Generation Resource is vulnerable to SSR in the event of five or six concurrent transmission Outages identified in the SSR vulnerability assessment and does not implement SSR Mitigation:

(a) ERCOT shall identify the combinations of Outages of Transmission Elements that may result in SSR vulnerability and provide these Transmission Elements to the affected Resource Entity and its interconnected TSP;

(b) ERCOT shall monitor the status of these Transmission Elements identified in paragraph (a) above;

(c) If the occurrence of Forced and/or Planned Outages results in a Generation Resource being three contingencies away from SSR vulnerability, ERCOT will identify options for mitigation that would be implemented if an additional transmission Outage were to occur, including communications with TSPs to determine potential Outage cancellations and time estimates to reinstate Transmission Facilities;

(d) If the occurrence of Forced and/or Planned Outages results in a Generation Resource being two contingencies away from SSR vulnerability, ERCOT shall take action to mitigate SSR vulnerability to the affected Generation Resource. ERCOT shall consider the actions in the following order unless reliability considerations dictate a different order. Actions that may be considered are:

(i) No action if the affected Generation Resource is equipped with SSR Protection and has elected for ERCOT to forego action to mitigate SSR vulnerability;

(ii) Coordinate with TSPs to withdraw or restore an Outage within eight hours if feasible;

(iii) If the actions described in (i) and (ii) above are not feasible, ERCOT shall promptly take necessary steps to identify and mitigate the impacts to the ERCOT System caused by bypassing the affected series capacitor(s) and direct the TSP(s) to bypass the affected series capacitors(s); or

(iv) Other actions specific to the situation, including, but not limited to, Verbal Dispatch Instruction (VDI) to the Resource’s Qualified Scheduling Entity (QSE).

(e) If the occurrence of Forced and/or Planned Outages results in a Generation Resource being one contingency away from SSR vulnerability, ERCOT shall promptly take necessary steps to identify and mitigate the impacts to the ERCOT System caused by bypassing the affected series capacitor(s) and direct the TSP(s) to bypass the affected series capacitor(s).

(f) If the occurrence of Forced and/or Planned Outages results in a Generation Resource being two or less contingencies away from SSR vulnerability, ERCOT shall notify the QSE representing the affected Generation Resource by voice communication as soon as practicable that the SSR vulnerability scenario has occurred; initiate the mitigation actions described in paragraphs (2)(d)(i) through (iv) above; and provide additional notifications to the QSE of each relevant topology change until the affected Generation Resource(s) is at least three contingencies away from SSR vulnerability.