**ERCOT Nodal Protocols**

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

**August 1, 2025**

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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 requested Outage plans for maintenance, repair, and construction of both Transmission Facilities and Resources within the ERCOT System. ERCOT may reject an Outage plan under certain circumstances, as set forth in these Protocols.

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

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

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| ***[NPRR857: Replace paragraph (a) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (a) Approving or rejecting requests for Planned Outages and Maintenance Outages of Transmission Facilities for Transmission Service Providers (TSPs) and Direct Current Tie Operators (DCTOs) in coordination with and based on information regarding all Entities’ Planned Outages and Maintenance Outages; |

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

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

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

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

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

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| ***[NPRR1234 and NPRR1246: Replace applicable portions of paragraph (f) above with the following upon system implementation for NPRR1234; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1246:]***  (f) Coordinating and approving or rejecting Outage plans affecting Subsynchronous Resonance (SSR) vulnerable Generation Resources and Energy Storage Resources (ESRs) that do not have SSO Mitigation in the event of five or six concurrent transmission Outages; |

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

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

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

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

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

(l) Establishing and implementing communication procedures:

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

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

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

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

(n) Planning and analyzing Transmission Facilities Outages.

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

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

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| ***[NPRR857: Replace paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (1) Each Resource Entity shall use reasonable efforts, consistent with Good Utility Practice, to continually update its Outage plans for all Outages. All information submitted about Planned Outages, Maintenance Outages, or Rescheduled Outages must be submitted by the Resource Entity, TSP, or DCTO under this Section. If an Outage plan for a Resource is also applicable to the Current Operating Plan (COP), the Qualified Scheduling Entity (QSE) responsible for the Resource shall also update the COP to provide the same information describing the Outage. Each TSP and DCTO shall use reasonable efforts, consistent with Good Utility Practice, to continually update its Outage plan, including, but not limited to, submitting the actual start and end date and time for Planned Outages of Transmission Facilities in the Outage Scheduler by hour ending 0800 of the current Operating Day for all scheduled work completed prior to hour ending 0600 of the current Operating Day. |

3.1.3 Rolling 12-Month Outage Planning and Update

**3.1.3.1 Transmission Facilities**

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

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| ***[NPRR857: Replace paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (1) Each TSP and DCTO shall provide to ERCOT a plan for Planned Outages, Maintenance Outages, and Rescheduled Outages in an ERCOT-provided format for the next 12 months updated monthly. Planned Outage, Maintenance Outage, and Rescheduled Outage scheduling data for Transmission Facilities must be kept current. Updates must identify all changes to any previously proposed Planned Outages, Maintenance Outages, or Rescheduled Outages and any additional Planned Outages, Maintenance Outages, or Rescheduled Outages anticipated over the next 12 months. ERCOT shall coordinate in-depth reviews of the 12-month plan with each TSP at least twice per year. |

**3.1.3.2 Resources**

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

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| ***[NPRR1246: Replace paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (1) Each Resource Entity shall provide to ERCOT a Planned Outage and Maintenance Outage plan for Generation Resources and ESRs in an ERCOT-provided format for at least the next 12 months updated monthly. Planned Outage and Maintenance Outage plans must be updated as soon as practicable following any change. Updates, through an electronic interface as specified by ERCOT, must identify any changes to previously proposed Planned Outages or Maintenance Outages and any additional Planned Outages or Maintenance Outages. |

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

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| ***[NPRR1240: Replace paragraph (2) above with the following upon system implementation:]***  (2) ERCOT shall report statistics monthly on how Resource Planned Outages compare with actual Resource Outages, and post those statistics to the ERCOT website. |

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.

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| ***[NPRR857: Replace paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (1) All communications concerning a Planned Outage, Maintenance Outage, or Rescheduled Outage must be between ERCOT and the designated “Single Point of Contact” for each TSP, DCTO, or Resource Entity. All nonverbal communications concerning Planned Outages or Rescheduled Outages must be conveyed through an electronic interface as specified by ERCOT. The TSP, DCTO, or Resource Entity shall identify, in its initial request or response, the Single Point of Contact, with primary and alternate means of communication. The Resource Entity, TSP, or DCTO shall submit a Notice of Change of Information (NCI) form (Section 23, Form E, Notice of Change of Information) when changes occur to a Single Point of Contact. This identification must be confirmed in all communications with ERCOT regarding Planned Outage, Maintenance Outage, or Rescheduled Outage requests. |

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

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| ***[NPRR857: Replace paragraph (2) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (2) The Single Point of Contact must be either a person or a position available seven days per week and 24 hours per day for each Resource Entity, TSP, or DCTO. The Resource Entity shall designate its QSE as its Single Point of Contact. The designated Single Point of Contact for a Generation Resource that has been split into two or more Split Generation Resources shall be the Master QSE. The Single Point of Contact for each TSP and DCTO must be designated under the ERCOT Operating Guides. |

**3.1.4.2 Method of Communication**

(1) ERCOT, each TSP, and each Resource Entity shall communicate according to ERCOT procedures under these Protocols. All submissions, changes, approvals, rejections, and withdrawals regarding Outages must be processed through the ERCOT Outage Scheduler on the ERCOT programmatic interface, except for Forced Outages and Maintenance Level I Outages, which must be communicated to ERCOT immediately via the Current Operating Plan (COP) 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.

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| ***[NPRR857: Replace paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (1) ERCOT and each TSP, DCTO, and Resource Entity shall communicate according to ERCOT procedures under these Protocols. All submissions, changes, approvals, rejections, and withdrawals regarding Outages must be processed through the ERCOT Outage Scheduler on the ERCOT programmatic interface, except for Forced Outages and Maintenance Level I Outages, which must be communicated to ERCOT immediately via the Current Operating Plan if submitted for a Resource and using the Outage Scheduler if submitted by a TSP or DCTO. This does not prohibit any verbal communication when the situation warrants it. ERCOT shall develop guidelines for the types of events that may require verbal communication. |

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

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

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| ***[NPRR857 and NPRR1014: Replace applicable portions of paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities for NPRR857; and upon system implementation for NPRR1014:]***  (1) Each Resource Entity, TSP, and DCTO shall submit information regarding proposed Planned Outages, Maintenance Outages, and Rescheduled Outages of Transmission Facilities or Planned Outages and Maintenance Outages of Generation Resources or Energy Storage Resources (ESRs) under procedures adopted by ERCOT. The obligation to submit that information applies to each Resource Entity that is responsible to operate or maintain a Generation Resource or ESR that is part of or that affects the ERCOT System. The obligation to submit that information applies to each TSP, DCTO, or Resource Entity that is responsible to operate or maintain Transmission Facilities that are part of or affect the ERCOT System. A Resource Entity, TSP, or DCTO is also obligated to submit information for Transmission Facilities or Generation Resources or ESRs that are not part of the ERCOT System or that do not affect the ERCOT System if that information is required for regional security coordination as determined by ERCOT. |

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

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

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

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

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| ***[NPRR857: Replace paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (1) In the event of a Forced Outage, after the affected equipment is removed from service, the Resource Entity or QSE, as appropriate, TSP, or DCTO must notify ERCOT of its action by: |

(a) For Resource Outages:

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

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

(iii) Updating the Outage Scheduler, if necessary.

(b) For Transmission Facilities Forced Outages:

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

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

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

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

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

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| ***[NPRR857: Replace paragraph (3) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (3) For Maintenance Outages, the Resource Entity or QSE, as appropriate, TSP, or DCTO shall notify ERCOT of any Resource or Transmission Facilities Maintenance Outage according to the Maintenance Outage Levels by updating the COP and Outage Scheduler. ERCOT shall coordinate the removal of facilities from service within the defined timeframes as specified by the TSP, DCTO, QSE, or Resource Entity in its notice to ERCOT. |

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

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

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| ***[NPRR857: Replace paragraph (5) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (5) Removal of a Resource or Transmission Facilities from service under Maintenance Outages must be coordinated with ERCOT. To minimize harmful impacts to the system in urgent situations, the equipment may be removed immediately from service, provided the Resource Entity, TSP, or DCTO immediately gives notice of such action to ERCOT. |

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

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

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

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

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

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| ***[NPRR1246: Replace paragraph (4) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (4) If the QSE is to receive the exemption described in paragraph (6)(d) of Section 8.1.1.4.1, Regulation Service and Generation Resource/Controllable Load Resource/Energy Storage Resource Energy Deployment Performance, and Ancillary Service Capacity Performance Metrics, the QSE will notify ERCOT Operators by voice communication of every Forced Outage, Forced Derate, or Startup Loading Failure within 15 minutes. |

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

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

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

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

**3.1.4.6 Outage Coordination of Potential Transmission Emergency Conditions**

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

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

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| ***[NPRR930: Insert paragraph (3) below upon system implementation and renumber accordingly:]***  (3) If there are Resources at multiple sites with approved or accepted Resource Outages, whose approval or acceptance could be withdrawn to meet the applicable transmission reliability standards, ERCOT shall utilize the process described in Section 3.1.6.9. |

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

**3.1.4.7 Reporting of Forced Derates**

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

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

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

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

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

(6) Each QSE shall timely update the telemetered HSL and COP unless in the reasonable judgment of the QSE, such compliance would create an undue threat to safety, undue risk of bodily harm, or undue damage to equipment. The QSE is excused from updating the telemetered HSL and/or COP only for so long as the undue threat to safety, undue risk of bodily harm, or undue damage to equipment exists. The time for updating the telemetered HSL and/or COP begins once the undue threat to safety, undue risk of bodily harm, or undue damage to equipment no longer exists.

**3.1.4.8 Resource Forced Outage Report**

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

(a) The Resource name;

(b) The Resource unit code;

(c) The Resource’s fuel type;

(d) The type of Outage or derate;

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

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

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

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

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

3.1.5 Transmission System Outages

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

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

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| ***[NPRR857: Replace paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (1) A TSP, DCTO, or Resource Entity shall request a Planned Outage or Maintenance Outage when any Transmission Facility that is part of the ERCOT Transmission Grid and defined in the Network Operations Model will be removed from its normal service. For Resource Entities within a Private Use Network, this only includes Transmission Facilities at the Point of Interconnection (POI). For TSP, DCTO, and Resource Entity requests, the requesting Entity shall enter such a request in the Outage Scheduler. Planned Outages, Maintenance Outages, or Rescheduled Outages for Electrical Buses will be treated as consequentially outaged Transmission Elements. In those cases where a TSP or DCTO enters the breaker and switch statuses associated with an Electrical Bus, a downstream topology processor will evaluate the breakers and switches associated with the applicable Electrical Bus to determine if the Electrical Bus is consequentially outaged, and to thereby designate the status of the Electrical Bus. Proposed Transmission Planned Outage or Maintenance Outage information submitted by a TSP, DCTO, or Resource Entity in accordance with this Section constitutes a request for ERCOT’s approval of the Outage Schedule associated with the Planned Outage or Maintenance Outage. ERCOT is not deemed to have approved the Outage Schedule associated with the Planned Outage or Maintenance Outage until ERCOT notifies the TSP, DCTO, or Resource Entity of its approval under procedures adopted by ERCOT. ERCOT shall evaluate requests under Section 3.1.5.11, Evaluation of Transmission Facilities Planned Outage or Maintenance Outage Requests. |

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

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| ***[NPRR857: Replace paragraph (2) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (2) ERCOT shall review and approve Planned Outages and Maintenance Outages of Transmission Facilities schedules. ERCOT shall transmit its approvals and rejections to TSPs and DCTOs via the ERCOT Outage Scheduler. Once approved, ERCOT may not withdraw its approval except under the conditions described in Section 3.1.5.7, Withdrawal of Approval of Approved Planned Outages, Maintenance Outages, and Rescheduled Outages of Transmission Facilities. |

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

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

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| ***[NPRR1246: Replace paragraph (4) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (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 or ESR may request that the TSP to which the Resource is interconnected disconnect the 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.

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| ***[NPRR1246: Replace paragraph (5) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (5) Within five Business Days after receiving a request from a Load Serving Entity (LSE) to disconnect a Generation Resource or ESR 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 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 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 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 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.

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| ***[NPRR857: Replace Section 3.1.5.2 above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  **3.1.5.2 Receipt of TSP and DCTO Requests by ERCOT**  (1) ERCOT shall acknowledge each request for approval of a Transmission Planned Outage or Maintenance Outage schedule within two Business Hours of the receipt of the request. ERCOT may request additional information or seek clarification from the TSP or DCTO regarding the information submitted for a proposed Planned Outage or Maintenance Outage for Transmission Facilities. |

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

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

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| 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.

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| ***[NPRR857: Replace Section 3.1.5.3 above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  **3.1.5.3 Timelines for Response by ERCOT for TSP and DCTO Requests**  (1) For Transmission Facilities Outages, ERCOT shall approve or reject each request in accordance with the following table:   |  |  | | --- | --- | | **Amount of time between the request for approval of the proposed Outage and the scheduled start date of the proposed Outage:** | **ERCOT shall approve or reject no later than:** | | Three days | 1800 hours, two days before the start of the proposed Outage | | Between four and eight days | 1800 hours, three days before the start of the proposed Outage | | Between nine days and 45 days | Four days before the start of the proposed Outage | | Between 46 and 90 days | 30 days before the start of the proposed Outage | | Greater than 90 days | 75 days before the start of the proposed Outage |   (2) For Outages scheduled at least three days before the scheduled start date of the proposed Outage, ERCOT shall make reasonable attempts to accommodate unusual circumstances that support TSP and DCTO requests for approval earlier than required by the schedule above.  (3) If circumstances prevent adherence to these timetables, ERCOT shall discuss the request status and reason for the delay of the approval with the requesting TSP or DCTO and make reasonable attempts to mitigate the effect of the delay on the TSP or DCTO.  (4) When ERCOT rejects a request for an Outage, ERCOT shall provide the TSP or DCTO, in written or electronic form, suggested amendments to the schedules of a Planned Outage or Maintenance Outage of Transmission Facilities. Any such suggested amendments accepted by the TSP or DCTO must be processed by ERCOT as a Planned Outage or Maintenance Outage of Transmission Facilities request under this Section. |

**3.1.5.4 Delay**

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

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| ***[NPRR857: Replace paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (1) ERCOT may delay its approval or rejection of a proposed Planned Outage or Maintenance Outage of a Transmission Facilities schedule if the requesting TSP or DCTO has not submitted sufficient or complete information within the time frames set forth in these Protocols. |

**3.1.5.5 Opportunity Outage of Transmission Facilities**

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

**3.1.5.6 Rejection Notice**

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

(a) Specific concerns causing the rejection;

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

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

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| ***[NPRR857: Replace paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (1) If ERCOT rejects a request, ERCOT shall provide the TSP or DCTO a written or electronic rejection notice that includes:  (a) Specific concerns causing the rejection;  (b) Possible remedies or transmission schedule revisions, if any that might mitigate the basis for rejection; and  (c) An electronic copy of the ERCOT study case for review by the TSP or DCTO. |

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

(a) To protect system reliability or security;

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

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

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

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

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

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

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| ***[NPRR857: Replace paragraph (3) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (3) When multiple proposed Planned Outages, Maintenance Outages, or Rescheduled Outages cause a reliability or security concern, ERCOT shall:  (a) Communicate with each TSP and DCTO to see if the TSP or DCTO will adjust its proposed Planned Outage, Maintenance Outage, or Rescheduled Outage schedule;  (b) Determine if each TSP or DCTO will agree to an alternative Outage schedule; or  (c) Reject, in ERCOT’s sole discretion, one or more proposed Outages, considering order of receipt and impact on the ERCOT Transmission Grid. |

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

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

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| ***[NPRR857: Replace paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (1) If ERCOT believes it cannot meet the applicable reliability standards and has exercised reasonable options, ERCOT may contact the TSP or DCTO for more information prior to its withdrawal of the approval for a Planned Outage, Maintenance Outage, or Rescheduled Outage. ERCOT shall inform the affected TSP or DCTO both orally and in written or electronic form as soon as ERCOT identifies a situation that may lead to the withdrawal of ERCOT’s approval. If ERCOT withdraws its approval, the TSP or DCTO may submit a new request for approval of the Planned Outage or Maintenance Outage schedule provided the new request meets the submittal requirements for Outage Scheduling. |

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

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| ***[NPRR857: Replace paragraph (2) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (2) In determining whether to withdraw approval, ERCOT shall duly consider whether the Planned Outage, Maintenance Outage, or Rescheduled Outage affects public infrastructure if ERCOT is made aware of such potential impacts by the TSP or DCTO (e.g., impacts on highways, ports, municipalities, and counties). |

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

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| ***[NPRR857: Replace paragraph (3) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (3) Prior to withdrawing the approval of a High Impact Outage (HIO) submitted with greater than 90-days’ notice, ERCOT shall coordinate with the TSP or DCTO and may convert the Planned Outage to a Rescheduled Outage. The Rescheduled Outage shall retain the same priority as the original Planned Outage. ERCOT shall attempt to keep the Outage within the same calendar month. |

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

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

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| ***[NPRR857: Replace paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (1) In considering TSP or DCTO requests, ERCOT shall give priority to Planned Outages, Maintenance Outages, and Rescheduled Outages in the order of receipt. |

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

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

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

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

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

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

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

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

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

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

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

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| ***[NPRR857: Replace paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (1) Transmission Facilities Outage requests submitted by a TSP or a DCTO must include the following Transmission Facilities-specific information:  (a) The identity of the Transmission Facilities, in the Network Operations Model, including TSP or DCTO and location;  (b) The nature of the work, by predefined classifications, to be performed during the proposed Transmission Facilities Outage;  (c) The preferred start and finish dates for the proposed Transmission Planned or Maintenance Outage;  (d) The time required to: (i) finish the Transmission Planned Outage or Maintenance Outage and (ii) restore the Transmission Facilities to normal operation;  (e) Primary and alternate telephone numbers for the TSP’s or DCTO’s Single Point of Contact, as described in Section 3.1.4.1, Single Point of Contact, and the name of the individual submitting the information;  (f) The scheduling flexibility (i.e., the earliest start date and the latest finish date for the Outage);  (g) Any Transmission Facilities that must be out of service to facilitate the TSP’s or DCTO’s request;  (h) Any remedial actions or special protection systems necessary during the Outage and the contingency that would require the remedial action or relay action; and  (i) Any other relevant information related to the proposed Outage or any unusual risks affecting the schedule. |

**3.1.5.10 Additional Information Requests**

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

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| ***[NPRR857: Replace paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (1) The requesting TSP or DCTO shall comply with any ERCOT requests for more information about, or for clarification of, the information submitted by the TSP or DCTO for a proposed Outage. |

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

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

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

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

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| ***[NPRR857: Replace item (b) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (b) Outage plans submitted by Resource Entities, TSPs, and DCTOs under Section 3.1, Outage Coordination; |

(c) Forced Outages of Transmission Facilities;

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

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

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| ***[NPRR1234 and NPRR1246: Replace applicable portions of item (e) above with the following upon system implementation for NPRR1234; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1246:]***  (e) Potential for the proposed Outages to cause SSR vulnerability to Generation Resources or ESRs that do not have SSO 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.

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| ***[NPRR857: Replace paragraph (2) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (2) When ERCOT approves a Maintenance Outage, ERCOT shall coordinate the timing of the appropriate course of action with the requesting TSP or DCTO. |

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

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| ***[NPRR857: Replace paragraph (3) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (3) When ERCOT identifies that an HIO has been submitted with 90-days or less notice, ERCOT may coordinate with the TSP or DCTO to make reasonable efforts to minimize the impact. |

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



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

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| ***[NPRR857: Replace paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (1) TSPs and DCTOs shall submit all requests for Planned Outages and Maintenance Outages or changes to existing approved Outages of Transmission Elements in the Network Operations Model to ERCOT no later than the minimum amount of time between the submittal of a request to ERCOT for approval of a proposed Outage and the scheduled start date of the proposed Outage, according to the following table: |

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| 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.

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| ***[NPRR1240: Insert paragraph (f) below upon system implementation:]***  (f) An updated list of current and future equipment in the Outage Scheduler by operator. |

3.1.6 Outages of Resources Other than Reliability Resources

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

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

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

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

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

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

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

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

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

(5) ERCOT shall accept Forced Outage plans.

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

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

**3.1.6.1 Receipt of Resource Requests by ERCOT**

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

**3.1.6.2 Resource Outage Plan**

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

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

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

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

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

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

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

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

**3.1.6.3 Additional Information Requests**

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

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

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

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

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

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

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

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

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

**3.1.6.5 Evaluation of Proposed Resource Outage**

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

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

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

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

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

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

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

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

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| --- | --- | --- |
| Amount of time between a request for approval of a Planned Outage and the scheduled start of the proposed Outage: | Maximum duration of a Planned Outage that may be approved with this lead time: | ERCOT shall approve or reject no later than: |
| Three days | Seven days | ERCOT shall approve or reject by 1800 hours, two days before the start of the proposed Outage |
| Between four and eight days | Seven days | ERCOT shall approve or reject by 1800 hours, three days prior to the start of the proposed Outage |
| Between nine and 15 days | 15 days | ERCOT shall approve or reject four days before the start of the requested Outage |
| Between 16 and 45 days | 180 days | ERCOT shall approve or reject within five Business Days after submission |
| Greater than 45 days but less than 60 months | 180 days | ERCOT shall approve or reject within five Business Days after submission |
| Greater than 60 months | 180 days | ERCOT shall approve or reject within five Business Days once the Outage start dates are within the 60-month window |

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

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

**3.1.6.7 Delay**

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

**3.1.6.8 Resource Outage Rejection Notice**

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

(a) Specific reasons causing the rejection; or

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

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

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

(b) Due to insufficient information regarding the Outage;

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

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

(e) As specified elsewhere in these Protocols.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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| ***[NPRR930: Replace paragraph (iv) above with the following upon system implementation:]***  (iv) ERCOT shall create proxy Energy Offer Curves for the Resource under paragraph (4)(d)(iii) of Section 6.5.7.3, Security Constrained Economic Dispatch; and |

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

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

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

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

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

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

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

(a) The Load forecast;

(b) Load forecast vendor selection;

(c) Wind forecast;

(d) Wind forecast vendor selection;

(e) Solar forecast;

(f) Solar forecast vendor selection;

(g) Expected severe weather impacts forecast;

(h) Targeted reserve levels;

(i) DC Tie import forecast;

(j) DC Tie export curtailment forecast;

(k) SODG and SOTG forecasts;

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

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

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

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| ***[NPRR995: Replace paragraph (7) above with the following upon system implementation:]***  (7) The preliminary OAE may not assume total renewable production lower than the sum of the selected Wind-powered Generation Resource Production Potential (WGRPP) and PhotoVoltaic Generation Resource Production Potential (PVGRPP) forecasts for each hour less any reasonably expected severe weather impacts. The available capacity in ERCOT’s preliminary OAE must include targeted reserve levels and include forecasted capacity available through DC Tie imports or curtailment of DC Tie exports, forecasted capacity provided from Settlement Only Distributed Generators (SODGs), Settlement Only Transmission Generators (SOTGs), Settlement Only Distribution Energy Storage Systems (SODESSs), and Settlement Only Transmission Energy Storage Systems (SOTESSs), and forecasted capacity from price-responsive Demand based on information reported to ERCOT in accordance with Section 3.10.7.2.1, Reporting of Demand Response. ERCOT must post the following inputs to the preliminary OAE to the ERCOT website within an hour of issuing an AAN, including but not limited to:  (a) The Load forecast;  (b) Load forecast vendor selection;  (c) Wind forecast;  (d) Wind forecast vendor selection;  (e) Solar forecast;  (f) Solar forecast vendor selection;  (g) Expected severe weather impacts forecast;  (h) Targeted reserve levels;  (i) DC Tie import forecast;  (j) DC Tie export curtailment forecast;  (k) SODG, SOTG, SODESS, and SOTESS forecasts;  (l) The forecast of capacity provided by price-responsive Demand;  (m) Any aggregate derating of Resource(s) and/or Forced Outage assumptions in total MWs; and  (n) Any aggregate fuel derating assumptions in total MWs. |

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

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

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

**3.1.6.10 Opportunity Outage**

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

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

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

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

**3.1.6.11 Outage Returning Early**

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

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

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

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

**3.1.6.12 Resource Coming On-Line**

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

**3.1.6.13 Maximum Daily Resource Planned Outage Capacity**

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

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

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

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

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

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

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

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

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

3.1.7 Reliability Resource Outages

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

(a) Load forecast;

(b) All other known Outages; and

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

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

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

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

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

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

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

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

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

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

3.1.8 High Impact Transmission Element (HITE) Identification

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

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| ***[NPRR1240: Replace paragraph (1) above with the following upon system implementation:]***  (1) ERCOT, with input from Market Participants, shall develop a list of HITEs. ERCOT, with input from Market Participants, shall develop a list of major transmission elements for review and approval at least annually by the TAC. |

3.2 Analysis of Resource Adequacy

3.2.1 Calculation of Aggregate Resource Capacity

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

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| ***[NPRR1014 and NPRR1029: Replace applicable portions of paragraph (1) above with the following upon system implementation:]***  (1) ERCOT shall use Outages in the Outage Scheduler and, when applicable, the Resource Status from the Current Operating Plan (COP) to calculate the aggregate capacity from Generation Resources, Energy Storage Resources (ESRs), and Load Resources projected to be available in the ERCOT Region and in Forecast Zones in ERCOT. “Forecast Zones” have the same boundaries as the 2003 ERCOT Congestion Management Zones (CMZs). Each Resource will be mapped to a Forecast Zone during the registration process. |

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

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| ***[NPRR1014 and NPRR1029: Replace applicable portions of paragraph (2) above with the following upon system implementation:]***  (2) On a rolling hourly basis, ERCOT shall calculate the aggregate hourly Generation Resource capacity, ESR capacity, and Load Resource capacity in the ERCOT Region and Forecast Zones projected to be available during each hour for the following seven days. |

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

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| ***[NPRR1029: Replace paragraph (3) above with the following upon system implementation:]***  (3) Projections of generation capacity from Intermittent Renewable Resources (IRRs) and the intermittent renewable generation components of DC-Coupled Resources shall be consistent with capacity availability estimates, such as the effective Load carrying capability of wind, developed jointly between ERCOT and the appropriate Technical Advisory Committee (TAC) subcommittee and approved by the ERCOT Board or typical production expectations consistent with expected wind profiles as appropriate for the scenario being studied. |

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

3.2.2 Demand Forecasts

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

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| ***[NPRR1240: Replace paragraph (1) above with the following upon system implementation:]***  (1) Monthly, ERCOT shall post on the ERCOT website the weekly peak hour Demand forecast for the ERCOT Region and for the Forecast Zones based on the 36-Month Load Forecast as described in Section 3.12, Load Forecasting, for the following 36 months, starting with the second week. During the development of this forecast, ERCOT may consult with Qualified Scheduling Entities (QSEs), Transmission Service Providers (TSPs), and other Market Participants that may have knowledge of potential Load growth. |

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

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| ***[NPRR1240: Replace paragraph (2) above with the following upon system implementation:]***  (2) ERCOT may, at its discretion, publish on the ERCOT website, additional peak Demand analyses for periods beyond 36 months. |

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

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

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

3.2.3 Short-Term System Adequacy Reports

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

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

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

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

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

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

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

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

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

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

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

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

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

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| ***[NPRR1007 and NPRR1029: Replace applicable portions of Section 3.2.3 above with the following upon system implementation for NPRR1029; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007:]***  ***3.2.3 Short-Term System Adequacy Reports***  (1) ERCOT shall generate and post short-term adequacy reports on the ERCOT website. ERCOT shall update these reports hourly following updates to the Seven-Day Load Forecast, except where noted otherwise. The short-term adequacy reports will provide:  (a) For Generation Resources, the available On-Line Resource capacity for each hour, aggregated by Forecast Zone, using the COP for the first seven days and considering Resources with a COP Resource Status listed in paragraph (5)(b)(i) of Section 3.9.1, Current Operating Plan (COP) Criteria;  (b) The total system-wide capacity of Resource Outages as reflected in the Outage Scheduler that are accepted or approved. The Resource Outage capacity amount shall be based from each Resource’s current Seasonal High Sustained Limit (HSL) and posted each hour for the top of each Operating Hour for the next 168 hours. This posted information will exclude specific Resource information and Outages related to Mothballed or Decommissioned Generation Resources, and will be aggregated on a Forecast Zone basis in three categories:  (i) IRRs and the intermittent renewable generation component of each DC-Coupled Resource with an Outage Scheduler nature of work other than “New Equipment Energization”;  (ii) Other Resources with an Outage Scheduler nature of work other than “New Equipment Energization”; and  (iii) Resources with an Outage Scheduler nature of work “New Equipment Energization”;  (c) For Load Resources, the available capacity for each hour aggregated by Forecast Zone, using the COP for the first seven days and considering Resources with a COP Resource Status of ONL;  (d) The total capability of Resources available to provide the following Ancillary Service combinations, using COPs submitted by QSEs for the first seven days and capped by the COP limits for individual Resources. A Resource’s capability shall only be included in the sums below if the Resource Status allows the Resource to provide at least one of the Ancillary Services within the sum:  (i) Capacity to provide Reg-Up, irrespective of whether it is capable of providing any other Ancillary Service;  (ii) Capacity to provide RRS, irrespective of whether it is capable of providing any other Ancillary Service;  (iii) Capacity to provide ECRS, irrespective of whether it is capable of providing any other Ancillary Service;  (iv) Capacity to provide Non-Spin, irrespective of whether it is capable of providing any other Ancillary Service;  (v) Capacity to provide Reg-Up, RRS, or both, irrespective of whether it is capable of providing ECRS or Non-Spin;  (vi) Capacity to provide Reg-Up, RRS, ECRS, or any combination, irrespective of whether it is capable of providing Non-Spin;  (vii) Capacity to provide Reg-Up, RRS, ECRS, Non-Spin, or any combination; and  (viii) Capacity to provide Reg-Down;  (e) Forecast Demand for each hour described in Section 3.2.2, Demand Forecasts;  (f) For Generation Resources, the available Off-Line Resource capacity that can be started for each hour, aggregated by Forecast Zone, using the COP for the first seven days and considering Resources with a COP Resource Status of OFF and temporal constraints;  (g) Following each Hourly Reliability Unit Commitment (HRUC), the available On-Line capacity from Generation Resources, aggregated by Forecast Zone, based on Real-Time telemetry, for which the COP Resource Status is OFF, OUT, or EMR for all hours within the HRUC Study Period. The available On-Line capacity will consider those Resources with a Real-Time Resource Status listed in paragraph (5)(b)(i) of Section 3.9.1 excluding SHUTDOWN;  (h) For each Direct Current Tie (DC Tie), the sum of any ERCOT-approved DC Tie Schedules for each 15-minute interval for the first seven days. The sum shall be displayed as an absolute value and classified as a net import or net export;  (i) The available capacity for each hour for the next seven days. For day one, and for day two following the execution of the Day-Ahead Reliability Unit Commitment (DRUC) on day one, the available capacity will be the sum of the values calculated in paragraphs (a) and (f) above, except that for IRRs the forecasted output will be used instead of COP values, and DC Tie exports will be subtracted. For the remaining hours of the seven days, the available capacity will be calculated as the sum of the Seasonal HSLs for non-IRR Generation Resources including seasonal Private Use Network capacity and the forecasted output for IRRs minus the total capacity of accepted or approved Resource Outages; and  (j) The available capacity for reserves for each hour, which will be the available capacity calculated in paragraph (i) above minus the forecasted Demand for that hour. |

3.2.4 [RESERVED]

3.2.5 Publication of Resource and Load Information

(1) Two days after the applicable Operating Day, ERCOT shall post on the ERCOT website for the ERCOT System and, if applicable, for each Disclosure Area, the information derived from the first complete execution of Security-Constrained Economic Dispatch (SCED) in each 15-minute Settlement Interval. The Disclosure Area is the 2003 ERCOT CMZs. Posting requirements will be applicable to Generation Resources and Controllable Load Resources (CLRs) 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:

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| ***[NPRR1007 and NPRR1014: Replace applicable portions of paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014:]***  (1) Two days after the applicable Operating Day, ERCOT shall post on the ERCOT website for the ERCOT System and, if applicable, for each Disclosure Area, the information derived from each execution of SCED. The Disclosure Area is the 2003 ERCOT CMZs. Posting requirements will be applicable to Generation Resources, ESRs, and Controllable Load Resources (CLRs) 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;

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| ***[NPRR1014: Insert paragraph (d) below upon system implementation and renumber accordingly:]***  (d) An aggregated energy supply and demand curve based on Energy Bid/Offer Curves that are available to SCED. The curves will be calculated beginning at the sum of the LSLs and ending at the sum of the HSLs for the Energy Bid/Offer Curves, with the dispatch for each Resource constrained between the Resource’s LSL and HSL. The result will represent the ERCOT System energy supply and demand curve economic dispatch of the ESRs with Energy Bid/Offer Curves at various pricing points, not taking into consideration any physical limitations of the ERCOT System; |

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

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| ***[NPRR1014: Replace paragraph (d) above with the following upon system implementation:]***  (e) The sum of LSLs, sum of Output Schedules, and sum of HSLs for Generation Resources without Energy Offer Curves and ESRs without Energy Bid/Offer Curves; |

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

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| ***[NPRR1007 and NPRR1014: Replace applicable portions of paragraph (e) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014:]***  (f) The sum of the Base Points of non-IRR Generation Resources with Energy Offer Curves, sum of the Base Points of WGRs with Energy Offer Curves, sum of the Base Points of PVGRs with Energy Offer Curves, sum of the Base Points of ESRs with Energy Bid/Offer Curves, and the sum of the Base Points of all remaining Resources dispatched in SCED; |

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

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

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| ***[NPRR1014 and NPRR1188: Replace applicable portions of paragraph (g) above with the following upon system implementation:]***  (h) An aggregate energy Demand curve based on the Energy Bid Curves available to SCED. The energy Demand curve will be calculated beginning at the sum of the Low Power Consumptions (LPCs) and ending at the sum of the Maximum Power Consumptions (MPCs), with the dispatch for each CLR constrained between the CLR’s LPC and MPC. The result will represent the ERCOT System Demand response capability available to SCED of the CLRs with Energy Bid Curves at various pricing points, not taking into consideration any physical limitations of the ERCOT System; |

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| ***[NPRR1007, NPRR1014, and NPRR1245: Insert applicable portions of paragraphs (i)-(k) below upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007 and NPRR1245; or upon system implementation for NPRR1014:]***  (i) The aggregate Ancillary Service Offers (prices and quantities) in the RTM for each type of Ancillary Service regardless of a Resource’s On-Line or Off-Line status. For RRS, ERCOT shall separately post aggregated offers from Resources providing Primary Frequency Response, Fast Frequency Response (FFR), and Load Resources controlled by high-set under-frequency relays. For ERCOT Contingency Reserve Service (ECRS) and Non-Spinning Reserve (Non-Spin), ERCOT shall separately post aggregated offers from Resources that are SCED-dispatchable and those that are manually dispatched. Linked Ancillary Service Offers will be included as non-linked Ancillary Service Offers;  (j) The sum of the Base Points of ESRs in discharge mode; and  (k) The sum of the Base Points of ESRs in charge mode. |

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

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| ***[NPRR1007 and NPRR1014: Replace applicable portions of paragraph (2) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014:]***  (2) Two days after the applicable Operating Day, ERCOT shall post on the ERCOT website for the ERCOT System the following information derived from each execution of SCED: |

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

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

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

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

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

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

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

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

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

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

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

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

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| ***[NPRR1007, NPRR1014, NPRR1188, and NPRR1245: Replace applicable portions of paragraph (3) above with the following upon system implementation for NPRR1014 or NPRR1188; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007 and NPRR1245:]***  (3) Two days after the applicable Operating Day, ERCOT shall post on the ERCOT website the following information for the ERCOT System and, if applicable, for each Disclosure Area from the DAM for each hourly Settlement Interval:  (a) An aggregate energy supply curve based on all energy offers that are available to the DAM, including the offer portion of Energy Bid/Offer Curves submitted for ESRs, not taking into consideration Resource Startup Offer or Minimum-Energy Offer or any physical limitations of the ERCOT System. The result will represent the energy supply curve at various pricing points for energy offers available in the DAM;  (b) Aggregate minimum energy supply curves based on all Minimum-Energy Offers that are available to the DAM;  (c) An aggregate energy Demand curve based on the DAM Energy Bids and Energy Bid Curves from CLRs and including the bid portion of Energy Bid/Offer Curves available to the DAM, not taking into consideration any physical limitations of the ERCOT System;  (d) The aggregate amount of cleared energy bids and offers including cleared Minimum-Energy Offer quantities;  (e) The aggregate Ancillary Service Offers (prices and quantities) in the DAM for each type of Ancillary Service regardless of a Resource’s On-Line or Off-Line status and including Ancillary Service Only Offers. For RRS, ERCOT shall separately post aggregated offers from Resources providing Primary Frequency Response (including Ancillary Service Only Offers), FFR, and Load Resources controlled by high-set under-frequency relays. For ECRS and Non-Spin, ERCOT shall separately post aggregated offers from Resources that are SCED-dispatchable (including Ancillary Service Only Offers) and those that are manually dispatched. Linked Ancillary Service Offers will be included as non-linked Ancillary Service Offers;  (f) The aggregate Self-Arranged Ancillary Service Quantity for each type of service by hour. For RRS, ERCOT shall separately post aggregated Self-Arranged Ancillary Service Quantities from Resources providing Primary Frequency Response, FFR, and Load Resources controlled by high-set under-frequency relays. For ECRS and Non-Spin, ERCOT shall separately post aggregated Self-Arranged Ancillary Service Quantities from Resources that are SCED-dispatchable and those that are manually dispatched;  (g) The aggregate amount of cleared Resource-specific Ancillary Service Offers and Ancillary Service Only Offers. For RRS, ERCOT shall separately post aggregated Ancillary Service Offers from Resources providing Primary Frequency Response (including Ancillary Service Only Offers), FFR, and Load Resources controlled by high-set under-frequency relays. For ECRS and Non-Spin, ERCOT shall separately post aggregated Ancillary Service Offers from Resources that are SCED-dispatchable (including Ancillary Service Only Offers) and those that are manually dispatched; and  (h) The aggregate Point-to-Point (PTP) Obligation bids (not-to-exceed price and quantities) for the ERCOT System and the aggregate PTP Obligation bids that sink in the Disclosure Area for each Disclosure Area. |

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

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| ***[NPRR1007 and NPRR1014: Replace applicable portions of paragraph (4) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014:]***  (4) ERCOT shall post on the ERCOT website the following information for each Resource for each execution of SCED 60 days prior to the current Operating Day: |

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

(i) As submitted;

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

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

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| ***[NPRR1000: Replace paragraph (iii) above with the following upon system implementation:]***  (iii) As mitigated and extended for use in SCED; |

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| ***[NPRR1007 and NPRR1014: Insert applicable portions of paragraph (b) below upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014; and renumber accordingly:]***  (b) The Resource name and the Resource’s Ancillary Service Offer Curve (prices and quantities) for each type of Ancillary Service:  (i) As submitted; and  (ii) As submitted and extended with proxy Ancillary Service Offer Curve logic by ERCOT. |

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

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| ***[NPRR1188: Replace paragraph (b) above with the following upon system implementation:]***  (b) The Load Resource name and the Load Resource’s Energy Bid Curve (prices and quantities); |

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

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

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

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

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

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

(i) The Generation Resource name;

(ii) The Generation Resource status;

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

(iv) The Generation Resource Base Point from SCED;

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

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

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

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| ***[NPRR1007 and NPRR1014: Replace applicable portions of paragraph (g) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014:]***  (h) The following Generation Resource data using a snapshot from each execution of SCED:  (i) The Generation Resource name;  (ii) The Generation Resource status;  (iii) The Generation Resource HSL, LSL, High Dispatch Limit (HDL), and Low Dispatch Limit (LDL);  (iv) The Generation Resource Base Point from SCED;  (v) The telemetered Generation Resource net output used in SCED;  (vi) The Ancillary Service Resource awards for each Ancillary Service;  (vii) The Generation Resource Startup Cost and minimum energy cost used in the Reliability Unit Commitment (RUC);  (viii) The telemetered Normal Ramp Rates;  (ix) The telemetered Ancillary Service capabilities; and |

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

(i) The Load Resource name;

(ii) The Load Resource status;

(iii) The MPC for a Load Resource;

(iv) The LPC for a Load Resource;

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

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

(vii) The telemetered real power consumption; and

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

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| ***[NPRR1007, NPRR1014, and NPRR1204: Replace applicable portions of paragraph (h) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007 and NPRR1204; or upon system implementation for NPRR1014:]***  (i) The following Load Resource data using a snapshot from each execution of SCED:  (i) The Load Resource name;  (ii) The Load Resource status;  (iii) The MPC for a Load Resource;  (iv) The LPC for a Load Resource;  (v) The Load Resource HDL and LDL, for a CLR that has a Resource Status of ONL;  (vi) The Load Resource Base Point from SCED, for a CLR that has a Resource Status of ONL;  (vii) The telemetered real power consumption;  (viii) The Ancillary Service Resource awards for each Ancillary Service;  (ix) The telemetered self-provided Ancillary Service amount for each Ancillary Service;  (x) The telemetered Normal Ramp Rates;  (xi) The telemetered Ancillary Service capabilities; and  (j) The ESR name and the ESR’s Energy Bid/Offer Curve (prices and quantities):  (i) As submitted; and  (ii) As submitted and extended with proxy Energy Offer Curve logic by ERCOT to fit to the operational HSL and LSL values that are available for dispatch by SCED;  (k) The following ESR data using a snapshot from each execution of SCED:  (i) The ESR name;  (ii) The ESR status;  (iii) The ESR HSL, LSL, High Dispatch Limit (HDL), and Low Dispatch Limit (LDL);  (iv) The ESR Base Point from SCED;  (v) The telemetered ESR net output used in SCED;  (vi) The Ancillary Service Resource awards for each Ancillary Service;  (vii) The telemetered Normal Ramp Rates;  (viii) The telemetered Ancillary Service capabilities;  (ix) The telemetered State of Charge in MWh;  (x) The telemetered Minimum State of Charge (MinSOC) in MWh; and  (xi) The telemetered Maximum State of Charge (MaxSOC) in MWh. |

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| ***[NPRR1007: Insert paragraph (5) below upon system implementation of the Real-Time Co-Optimization (RTC) project and renumber accordingly:]***  (5) ERCOT shall post on the ERCOT website for each Resource for each Operating Hour 60 days prior to the current Operating Day a count of the number of times for each Ancillary Service that the Resource’s Ancillary Service Offer quantity or price was updated within the Operating Period. ERCOT shall post on the ERCOT website for each Resource for each Operating Hour 60 days prior to the current Operating Day, a count of the number of times a Resource’s Energy Offer quantity or price was updated within the Operating Hour, including any reason accompanying the update. |

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

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| ***[NPRR1007 and NPRR1014: Replace applicable portions of paragraph (5) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014:]***  (6) If any Real-Time Locational Marginal Price (LMP) exceeds 50 times the Fuel Index Price (FIP) during any SCED interval for the applicable Operating Day, ERCOT shall post on the ERCOT website the portion of any Generation Resource’s as-submitted and as-mitigated and extended Energy Offer Curve or any ESR’s as-submitted and as-mitigated and extended Energy Bid/Offer Curve that is at or above 50 times the FIP for that SCED interval seven days after the applicable Operating Day. |

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

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| ***[NPRR1007 and NPRR1014: Replace applicable portions of paragraph (6) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014:]***  (7) If any Market Clearing Price for Capacity (MCPC) for an Ancillary Service exceeds 50 times the FIP for any Operating Hour in a DAM or any SCED interval in the RTM for the applicable Operating Day, ERCOT shall post on the ERCOT website the portion on any Resource’s Ancillary Service Offer that is at or above 50 times the FIP for that Ancillary Service for that Operating Hour for the DAM or SCED interval for the RTM seven days after the applicable Operating Day. |

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

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

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

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| ***[NPRR1007 and NPRR1014: Replace applicable portions of paragraph (9) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014:]***  (10) ERCOT shall post on the ERCOT website the offer price and the name of the Entity submitting the offer for the highest-priced Ancillary Service Offer selected in the DAM or RTM for each Ancillary Service three days after the end of the applicable Operating Day. If multiple Entities submitted the highest-priced offers selected, all Entities shall be identified on the ERCOT website. The report shall specify whether the Ancillary Service Offer was selected in a DAM or RTM. |

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

(a) The Resource name;

(b) The name of the Resource Entity;

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

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

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

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

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

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

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| ***[NPRR1007 and NPRR1014: Insert applicable portions of paragraph (d) below upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014; and renumber accordingly:]***  (d) The Ancillary Service Only Offer for each Ancillary Service and the name of the QSE submitting the offer; |

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

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

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

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

(h) The award for 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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| ***[NPRR1188: Insert items (l) and (m) below upon system implementation and renumber accordingly:]***  (l) The CLR name and the CLR’s Energy Bid Curve (prices and quantities) available for the DAM; and  (m) The award for each CLR’s Energy Bid Curve from the DAM and the name of the QSE receiving the award. |

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| ***[NPRR1014: Insert items (m)-(o) below upon system implementation:]***  (m) The ESR name and the ESR’s Energy Bid/Offer Curve (prices and quantities), available for the DAM;  (n) The awards for each Ancillary Service from the DAM for each ESR; and  (o) The award for each Energy Bid/Offer Curve from the DAM and the name of the QSE receiving the award. |

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

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

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

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

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

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

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

(2) Within ten Business Days after the end of each quarter, each NOIE shall submit to ERCOT electronically the required data described below as of the last day of the prior quarter by submitting the designated form provided on the ERCOT website. NOIEs that have an unregistered DG capacity of more than two MW, based upon the aggregate capacity of all sites that are less than 50 kW, shall report the total of all unregistered DG MW capacity, inclusive of systems used to support self-serve Load. All other NOIEs shall report the aggregate unregistered DG capacity of only those sites greater than or equal to 50 kW, inclusive of systems used to support self-serve Load. NOIEs shall report their capacity by Load Zone and by primary fuel type as follows:

(a) Solar;

(b) Wind;

(c) Other renewable; and

(d) Other non-renewable.

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

(a) Solar;

(b) Wind;

(c) Other renewable; and

(d) Other non-renewable.

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

**3.2.5.2 Unregistered Distributed Generation Reporting Requirements for Competitive Areas**

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

**3.2.5.3 Unregistered Distributed Generation Reporting Requirements for ERCOT**

(1) Within 30 days after the end of each quarter, ERCOT shall publish the unregistered DG report on the ERCOT website. This report shall include the aggregated data compiled for NOIE and competitive areas. This report shall include the total unregistered DG MW capacity, as provided in accordance with Section 3.2.5.1, Unregistered Distributed Generation Reporting Requirements for Non Opt-In Entities, and Section 3.2.5.2, Unregistered Distributed Generation Reporting Requirements for Competitive Areas, above, by Load Zone and by primary fuel type as follows:

(a) Solar;

(b) Wind;

(c) Other renewable; and

(d) Other non-renewable.

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

3.2.6 Report on Capacity, Demand and Reserves in the ERCOT Region

(1) ERCOT shall prepare and publish the Report on Capacity, Demand and Reserves in the ERCOT Region (CDR) twice per year. ERCOT will target the posting of the preliminary CDR during the third week of each May and the final CDR during the third week of each December. ERCOT will issue a Market Notice indicating a revised posting date if that date is anticipated to occur prior to or after the target posting week.

(2) Load and capacity forecasts shall be reported for at least the next five years beyond the year that the CDRs are published. Seasonal forecasts, as defined in Section 3.2.6.1, Planning Reserve Margins, shall also be prepared and published for each forecast year.

(3) The format and other contents of this report shall be developed by ERCOT with guidance from the Wholesale Market Subcommittee (WMS) and its working group designated to periodically review the report contents.

(4) The CDR shall provide peak Load, peak Net Load, and capacity estimates based on the methodologies in Section 3.2.6.1, Section 3.2.6.2, Effective Load Carrying Capability (ELCC) Studies, Section 3.2.6.3, Firm Peak Load and Firm Peak Net Load Estimates, and Section 3.2.6.4, Total Capacity Estimates.

**3.2.6.1 Planning Reserve Margins**

(1) ERCOT shall calculate a Planning Reserve Margin (PRM) for each season of each future year reflecting Loads and resources for the forecasted peak Load hour and peak Net Load hour as follows:

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

The above variables are defined as follows:

| Variable | Unit | Definition |
| --- | --- | --- |
| PRM *h, s, i* | % | *Planning Reserve Margin*—The Planning Reserve Margin for hour *h* of season *s* for year *i*. |
| TOTCAP *h, s, i* | MW | *Total Capacity*—Total Capacity available for hour *h* of season *s* for the year *i.* |
| FIRMPKLD *h, s, i* | MW | *Firm Peak Load*—Firm Peak Load for hour *h* of the season *s* for the year *i*. |
| *h* | None | The forecasted peak Load hour and peak Net Load hour. |
| *i* | None | Year. |
| *s* | None | Season. Summer Peak Load Season, Winter Peak Load Season, Spring (March, April, May), and Fall (October and November), for year *i*. |

**3.2.6.2 Effective Load Carrying Capability (ELCC) Studies**

(1) ERCOT shall conduct an Effective Load Carrying Capability (ELCC) study every three years or as necessary based on reviews of expected resource penetration and generation technology trends using Generator Interconnection or Modification (GIM) data. ERCOT shall provide the appropriate WMS working group with a draft ELCC report and subsequent review and comment period before finalizing the ELCC report. The ELCC reports shall be posted to the ERCOT website.

(2) The ELCC study shall be based on the Reliability Standard established by the Public Utility Commission of Texas (PUCT).

(3) ERCOT shall use a Monte Carlo system simulation tool for determining the ELCC values.

(4) The ELCC study will determine average ELCCs for aggregate WGRs, PVGRs and Energy Storage Resources (ESRs) by reserve risk period and applicable CDR resource regions as defined in Section 3.2.6.4, Total Capacity Estimates. Average ELCCs for aggregate ESRs shall be based on duration categories specified in the ELCC study.

(5) The ELCC study shall produce a range of ELCC values reflecting feasible future mixes of WGRs, PVGRs, ESRs and Load forecasts for the next five future years. Each CDR will include the ELCCs associated with the resource mix and load forecast for the given forecast year, season, and CDR resource region (in the case of WGRs and PVGRs).

**3.2.6.3 Firm Peak Load and Firm Peak Net Load Estimates**

(1) ERCOT shall prepare, at least annually, a forecast of total hourly Loads for 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. For the CDR, firm peak Load and firm peak Net Load estimates shall be determined by the following equation:

**FIRMPKLD *h,* *s, i* = TOTPKLD *h,* *s*, *i* – LRRRS *h*, *s, i* –LRECRS *h*, *s, i*** **–LRNSRS­ *h*, *s, i* – ERS *h*, *s, i* – DVR *s, i* – CLR *h*, *s, i***

The above variables are defined as follows:

|  |  |  |
| --- | --- | --- |
| **Variable** | **Unit** | **Definition** |
| FIRMPKLD *h,* *s, i* | MW | *Firm Peak Load Estimates*—The Firm Load forecasts for hour *h* for season *s* for year *i.* |
| TOTPKLD *h*, *s, i* | MW | *Total Peak Load Estimates*—The Firm Load forecasts for hour *h* for season *s* for year *i*. |
| LRRRS *h*, *s, i* | MW | *Load Resource providing RRS*—The amount of RRS a Load Resource is providing for hour *h* for season *s* for the year *i*. |
| LRECRS *h*, *s, i* | MW | *Load Resource providing ECRS*—The amount of ECRS a Load Resource is providing for hour *h* season *s* for the year *i*. |
| LRNSRS *h*, *s, i* | MW | *Load Resource providing Non-Spinning Reserve (Non-Spin)*—The estimated amount of Non-Spin that Load Resources are providing for hour *h* for season *s* for the year *i.* |
| ERS *h*, *s, i* | MW | *Emergency Response Service (ERS)*—The estimated amount of ERS for hour *h*, season *s*, and year *i*. For the first and subsequent forecast years, the seasonal and hourly forecast values are based on the most recent past procurements for the Standard Contract Term and ERS Time Periods during which the peak Load hour and peak Net Load hour are expected to occur. The seasonal ERS Contract Terms are as follows:   |  |  | | --- | --- | | **Season** | **Contract Term** | | Winter | December 1 to March 31 | | Spring | April 1 through May 31 | | Summer | June 1 through September 30 | | Fall | October 1 through November 30 |   Adjustments to the ERS amounts may be applied for each forecast year based on ERCOT consideration of expected program modifications, procurement methodology changes, changes in the seasonal risk assessments, and ERS time period expenditure limits. |
| DVR *h*, *s, i* | MW | *Distribution Voltage Reduction*—ERCOT-directed deployment of distribution voltage reduction measures for hour *h* of season *s* of the year *i* based on reduction estimates provided by Transmission and/or Distribution Service Providers (TDSPs). |
| CLR *h*, *s, i* | MW | *Amount of Controllable Load Resource*—Estimated amount of Controllable Load Resources that is available for Dispatch by ERCOT during the current year *i* for hour *h* and season *s*,not already included in LRRRS, LRECRS, or LRNSRS. This value does not include Wholesale Storage Load (WSL). |
| *h* | None | The forecasted peak Load hour and forecasted peak Net Load hour. |
| *i* | None | Year. |
| *s* | None | Season. Summer Peak Load Season, Winter Peak Load Season, Spring (March, April, May), and Fall (October and November), for year *i*. |

(2) The CDR shall also provide the estimated annual peak Load reduction amounts reflected in the firm peak Load forecast due to energy efficiency programs procured by TDSPs pursuant to P.U.C. Subst. R. 25.181, Energy Efficiency Goal, for year *i.* ERCOT will also include energy efficiency and/or Demand response initiatives reported by NOIEs.

**3.2.6.4 Total Capacity Estimates**

(1) Total capacity estimates will be based on generation availability at the time of the forecasted peak Load hour and peak Net Load hour for each future season and year.

(2) The total capacity estimates shall be determined based on the following equation:

**TOTCAP *h,* *s, i* = INSTTHERMCAP *s*, *i +* PUNCAP *p,* *s, i +* WINDCAP *p,* *s, i, wr* + HYDROCAP *p,* *s, i* + SOLARCAP *p,* *s,*** ***i, sr* + ESRCAP *p, s, i* + RMRCAP *s,*** ***i* + DCTIECAP *s* + PLANDCTIECAP** *s* **+ SWITCHCAP *s, i* + MOTHCAP *s, i* + PLANTHERMCAP *s, i* + PLANWINDCAP *p,* *s, i, wr* + PLANSOLARCAP *p,* *s, i, sr* + PLANESRCAP** *p, s, i* **– LTOUTAGE *s, i* – UNSWITCH *s, i* – RETCAPNSO *s, i* – RETCAPUNC *s, i***

The above variables are defined as follows:

| **Variable** | **Unit** | **Definition** |
| --- | --- | --- |
| TOTCAP *h,* *s, i* | MW | *Total Capacity*—Estimated total capacity available during the peak Load hour and peak Net Load hour *h* for season *s* for the year *i.* |
| INSTTHERMCAP *s, i* | MW | *Seasonal Net Max Sustainable Rating for each Thermal Generation Resource*—The Seasonal net maximum sustainable rating for season *s* as reported in the Resource Integration and Ongoing Operations (RIOO) system for each thermal operating Generation Resource for the year *i* excluding Resources operating under RMR Agreements, Mothballed Generation Resources, and Generation Resources capable of “switching” from the ERCOT Region to a non-ERCOT Region. For thermal generation resources classified as small generators in accordance with paragraph (3) of Planning Guide Section 5.2.1, Applicability, capacity is considered operational once a Model Ready Date has been assigned to the resource. |
| PUNCAP *h,* *s, i* | MW | *Private Use Network Capacity*—The forecasted generation capacity available to the ERCOT Transmission Grid, net of self-serve load, from Generation Resources and Settlement Only Generators (SOGs) in Private Use Networks for hour *h*, season *s,* and year *i*. The capacity forecasts are developed as follows. First, a base capacity forecast, determined from SCED data, is calculated as the average net generation capacity available to the ERCOT Transmission Grid during the 20 highest system-wide peak Load and peak Net Load hours for each preceding three-year period for 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 season *s* for forecast year *i* reported for Private Use Networks pursuant to Section 10.3.2.4, Reporting of Net Generation Capacity. This calculation is limited to Generation Resources and SOGs in Private Use Networks (1) with a Resource Commissioning Date that occurs no later than the start of the most current Season used for the calculation, and (2) that have not been permanently retired by the start of the most current Season used for the calculation. |
| HYDROCAP *p*, *s, i* | MW | *Hydro Unit Capacity*—The average hydro Generation Resource capacity available, as determined from SCED data during the highest 20 peak Load hours for each preceding three-year period for Reserve Risk Period *p*, 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. |
| WINDELCC *p, s, i, wr* | % | *Effective Load Carrying Capability for Wind*—The average ELCC for all WGRs for Reserve Risk Period *p*, season *s*, year *i*, and region *wr*, expressed as a percentage. |
| WINDCAP *p,* *s, i, wr* | MW | *Existing WGR Capacity*—The amount of currently operational WGRs for Reserve Risk Period *p*, season *s,* year *i*, and region *wr*, multiplied by WINDELCC *p*, *s*, *i*, wr. Capacity is considered operational if it has an ERCOT Resource Commissioning Date or ERCOT has approved, or expects to approve, the capacity for grid synchronization by the start of season *s* for year *i*. For wind resources classified as small generators in accordance with paragraph (3) of Planning Guide Section 5.2.1, capacity is considered operational once a Model Ready Date has been assigned to the resource. |
| SOLARELCC *p, s, i, sr* | % | *Effective Load Carrying Capability for Solar*—The average ELCC for Reserve Risk Period *p*, season *s*, year *i*, and region s*r*, expressed as a percentage. |
| SOLARCAP *p, s, i, sr* | MW | *Available PVGR and Small Generator Capacity*—The amount of PVGR capacity that is currently operational for Reserve Risk Period *p*, season *s,* year *i*, and region *sr*, multiplied by SOLARELCC *p,* *s, i, sr*. Capacity is considered operational if it has an ERCOT Resource Commissioning Date or ERCOT has approved, or expects to approve, the capacity for grid synchronization by the start of season *s* for year *i*. For solar resources classified as small generators in accordance with paragraph (3) of Planning Guide Section 5.2.1, capacity is considered operational once a Model Ready Date has been assigned to the resource. |
| ESRELCC *p, s, i* | % | *Effective Load Carrying Capability for Energy Storage Resources*—The average ELCC for Reserve Risk Period *p*, season *s*, and year *i*, expressed as a percentage. |
| ESRCAP *p, s, i* | % | *Available Energy Storage Resource Capacity*—The amount of ESR capacity by Reserve Risk Period *p*, season *s*, and year *i* that is currently operational, multiplied by ESRELCC *p, r, s, i.* Capacity is considered operational if it has an ERCOT Resource Commissioning Date or ERCOT has approved, or expects to approve, the capacity for grid synchronization by the start of season *s* for year *i*. For ESRs classified as small generators in accordance with paragraph (3) of Planning Guide Section 5.2.1, capacity is considered operational once a Model Ready Date has been assigned to the resource. |
| RMRCAP *s, i* | MW | *Seasonal Net Max Sustainable Rating for Generation Resource providing RMR Service*—The Seasonal net maximum sustainable rating for season *s* as reported in the RIOO system 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. |
| DCTIEPEAKPCT *s* | % | *Seasonal Net Import Capacity for existing DC Tie Resources as a Percent of Installed DC Tie Capacity*—The average net emergency DC Tie imports for season *s*, divided by the total installed DC Tie capacity for season *s*, expressed as a percentage. The average net emergency DC Tie imports is calculated for the SCED intervals during which ERCOT declared an Energy Emergency Alert (EEA). This calculation is limited to the most recent Seasons in which an EEA was declared. For the spring and fall seasons ERCOT will use the winter and summer values, respectively, if no EEA events have occurred for these seasons. The total installed DC Tie capacity is the capacity amount at the start of the Seasons used for calculating the net DC Tie imports. |
| DCTIECAP *s* | MW | *Expected Existing DC Tie Capacity Available under Emergency Conditions*—DCTIEPEAKPCT*s* multiplied by the installed DC Tie capacity available for season *s*, adjusted for any known capacity transfer limitations. |
| PLANDCTIECAP *s* | MW | *Expected Planned DC Tie Capacity Available under Emergency Conditions*—DCTIEPEAKPCT*s* multiplied by the maximum peak import capacity of planned DC Tie projects included in the most recent Steady State Working Group (SSWG) base cases, for season *s*. The import capacity may be adjusted to reflect known capacity transfer limitations indicated by transmission studies. |
| SWITCHCAP *s, i* | MW | *Seasonal Net Max Sustainable Rating for Switchable Generation Resources*—The Seasonal net maximum sustainable rating for season *s* as reported in the RIOO system for each Generation Resource for 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 maximum sustainable rating for season *s* as reported in the RIOO system for each Mothballed Generation Resource for 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 75%, then use the Seasonal net maximum sustainable rating for season *s* as reported in the RIOO system for the Mothballed Generation Resource for year *i*. If the value furnished by the owner of a Mothballed Generation Resource pursuant to Section 3.14.1.9 is less than 75%, then exclude that Resource from the Total Capacity Estimate. |
| PLANTHERMCAP *s, i* | MW | *New Thermal Generating Capacity*—The amount of new thermal generating capacity available by the start of 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, (d) has a signed Standard Generation Interconnection Agreement (SGIA), or a public, financially-binding agreement between the Resource owner and TSP under which generation interconnection facilities would be constructed; or for a Municipally Owned Utility (MOU) or Electric Cooperative (EC), a public commitment letter to construct a new Resource, (e) a written notice from the TSP that the Interconnecting Entity (IE) has provided notice to proceed with the construction of the interconnection, and (f) provided the TSP with sufficient financial security to fund the interconnection facilities. New, Thermal generating capacity is excluded if the GIM project status in the RIOO interconnection services system is set to “Cancelled” or “Inactive” or if the Resource was previously mothballed or retired and does not have an owner that intends to operate it. For the purposes of this section, ownership of a mothballed or retired Resource for which a new generation interconnection is sought can only be satisfied by proof of site control as described in paragraph (1)(a), (b), or (d) of Planning Guide Section 5.3.2.1, Proof of Site Control. Thermal resources classified as small generators in accordance with paragraph (3) of Planning Guide Section 5.2.1 must have an ERCOT-assigned Model Ready Date. |
| PLANWINDCAP *p, s, i, wr* |  | *New WGR Capacity*—For new WGRs, the capacity available by the start of season *s*, Reserve Risk Period *p*, year *i*, and region *wr*, multiplied by WINDELCC for season *s* for Reserve Risk Period *p*,year *i*, and Region *wr*. New WGRs must have (1) 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 WGR, (2) a written notice from the TSP that the IE has provided notice to proceed with the construction of the interconnection, and (3) provided the TSP with sufficient financial security to fund the interconnection facilities. Wind resources classified as small generators in accordance with paragraph (3) of Planning Guide Section 5.2.1 must have an ERCOT-assigned Model Ready Date. |
| PLANSOLARCAP *p, s, i, sr* |  | *New PVGR Capacity*—For new PVGRs, the capacity available by the start of season *s* for Reserve Risk Period *p*, year *i*, and region *sr*, multiplied by SOLARELCC *p*, *s*, *i*, *sr*. New PVGRs must have (1) 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 WGR, (2) a written notice from the TSP that the IE has provided notice to proceed with the construction of the interconnection, and (3) provided the TSP with sufficient financial security to fund the interconnection facilities. Solar resources classified as small generators in accordance with paragraph (3) of Planning Guide Section 5.2.1 must have an ERCOT-assigned Model Ready Date. |
| PLANESRCAP *p, s, i* | MW | *Available Energy Storage Resource Capacity*—The amount of ESR capacity that ERCOT has approved, or expects to approve, for grid synchronization by the start of season *s* for Reserve Risk Period *p* and year *i*, multiplied by ERSELCC *p,* *s, i.* |
| LTOUTAGE *s, i* | MW | *Forced Outage Capacity Reported in a Notification of Suspension of Operations—*For Generation Resources whose operation has been suspended due to a Forced Outage as reported in a Notification of Suspension of Operations (NSO), the sum of Seasonal net maximum sustainable ratings for season *s* and year *i*, as reported in the NSO forms. For Inverter-Based Resources (IBRs) use WINDCAP, SOLARCAP, and ESRCAP rather than ratings reported in NSOs. |
| 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 season *s* and year *i* pursuant to paragraph (2) of Section 16.5.4, Maintaining and Updating Resource Entity Information. |
| RETCAPNSO *s, i* | MW | *Capacity Pending Retirement*—The amount of capacity in season *s* of year *i* that is pending retirement based on information submitted on an NSO form (Section 22, Attachment E, Notification of Suspension of Operations) pursuant to Section 3.14.1.11, Budgeting Eligible Costs, but is under review by ERCOT pursuant to Section 3.14.1.2, ERCOT Evaluation Process, that has not otherwise been considered in any of the above defined categories. For Generation Resources and SOGs within Private Use Networks, the retired capacity amount is deducted from PUNCAP. |
| RETCAPUNC *s, i* | MW | *Unconfirmed Planned Retirements*—The capacity of Generation Resources for which a public announcement of the intent to permanently shut the unit down has been released, but a Notice of Suspension of Operations for the unit has not been received by ERCOT. To be considered an Unconfirmed Planned Retirement, the Generation Resource must meet the following criteria: (1) a specific retirement date is cited in the announcement, or other timing information is given that indicates the unit will be unavailable as of the start of season *s* for year *i*, and (2) the announcement, with follow-up inquiry by ERCOT, does not indicate that retirement timing is highly speculative. |
| *p* | None | Reserve Risk Period. The range of consecutive hours having the highest risk of operating reserve shortages for each season as determined by an ELCC study per Section 3.2.6.2, Effective Load Carrying Capability (ELCC) Studies. |
| *h* | None | The forecasted peak Load hour and forecasted peak Net Load hour. |
| *i* | None | Year. |
| *s* | None | Season.  Spring (March through May)  Summer (June through September)  Fall (October through November)  Winter (December through February) |
| *sr* | None | West, Far West, and Other solar regions. PVGRs are classified into regions based on the county that contains their Point of Interconnection Bus (POIB).  The West region is defined as the following counties: Archer, Armstrong, Bailey, Baylor, Borden, Briscoe, Callahan, Carson, Castro, Childress, Clay, Cochran, Coke, Coleman, Collingsworth, Concho, Cottle, Crockett, Crosby, Dallam, Dawson, Deaf Smith, Dickens, Donley, Fisher, Floyd, Foard, Garza, Glasscock, Gray, Hale, Hall, Hansford, Hardeman, Hartley, Haskell, Hockley, Howard, Hutchinson, Irion, Jones, Kent, King, Knox, Lamb, Lipscomb, Lubbock, Lynn, Martin, Menard, Mitchell, Moore, Motley, Nolan, Ochiltree, Oldham, Parmer, Potter, Randall, Reagan, Roberts, Runnels, Schleicher, Scurry, Shackelford, Sherman, Sterling, Stonewall, Sutton, Swisher, Taylor, Terry, Throckmorton, Tom Green, Val Verde, Wheeler, Wichita.  The Far West region is defined as the following counties: Andrews, Brewster, Crane, Culberson, Ector, El Paso, Gaines, Hudspeth, Jeff Davis, Loving, Midland, Pecos, Presidio, Reeves, Terrell, Upton, Ward, Winkler, Yoakum.  The Other solar region consists of all other counties in the ERCOT Region. |
| *wr* | None | Coastal, Panhandle, and Other wind regions. WGRs are classified into regions based on the county that contains their POIB.  The Coastal region is defined as the following counties: Aransas, Brazoria, Calhoun, Cameron, Kenedy, Kleberg, Matagorda, Nueces, Refugio, San Patricio, and Willacy.  The Panhandle region is defined as the following counties: Armstrong, Bailey, Briscoe, Carson, Castro, Childress, Cochran, Collingsworth, Crosby, Dallam, Deaf Smith, Dickens, Donley, Floyd, Gray, Hale, Hall, Hansford, Hartley, Hemphill, Hockley, Hutchinson, Lamb, Lipscomb, Lubbock, Moore, Motley, Ochiltree, Oldham, Parmer, Potter, Randall, Roberts, Sherman, Swisher, and Wheeler.  The Other region consists of all other counties in the ERCOT Region. |

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| ***[NPRR1267: Insert Section 3.2.7 below upon system implementation:]***  ***3.2.7 Large Load Interconnection Status Report***  (1) For purposes of this section, a Large Load is inclusive of one or more Facilities at a single site with an aggregate peak Demand greater than or equal to 75 MW behind one or more common Points of Interconnection (POIs) or Service Delivery Points that is seeking interconnection on or after March 25, 2022. ERCOT may expand the criteria for including a Load as a Large Load, provided the defining criteria are clearly stated in the applicable report.  (2) ERCOT must publish a Large Load interconnection status report each month to the ERCOT website that aggregates Large Load interconnection requests across multiple dimensions with as much specificity as possible while maintaining the confidentiality of Customer data, including:  (a) Load Zone;  (b) TSP;  (c) Load type (as provided to the TSP, such as refinery, steel mill, data center, etc.);  (d) Calendar quarter and year in which the interconnecting TSP submitted the project to ERCOT;  (e) Requested energization quarter and year;  (f) Size range;  (g) Interconnection status (as defined by ERCOT to differentiate between operational, approved, under study, etc.); and  (h) Co-location status.  (3) ERCOT shall take actions such as providing ranges of interconnection MW sizes, aggregate loads, and other similar actions to protect, anonymize, and otherwise safeguard confidential and competitively-sensitive Customer data from public disclosure. When aggregating Customer data, ERCOT should ensure that at least five Customers exist in a particular Load type subcategory prior to aggregation, to protect against accidental disclosure. ERCOT may leave a certain category blank or aggregated with other Load types to avoid disclosure.  (4) ERCOT shall report to TAC or its designated subcommittee its methodology for developing the report defined in paragraph (2) above whenever that methodology changes, but at least every two years. |

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.

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| ***[NPRR857: Replace paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (1) Before energizing and placing into service any new or relocated facility connected to the ERCOT Transmission Grid, a Transmission Service Provider (TSP), Direct Current Tie Operator (DCTO), Qualified Scheduling Entity (QSE), or Resource Entity shall enter appropriate information in the Outage Scheduler and coordinate with, and receive written notice of approval from, ERCOT. |

3.3.2 Types of Work Requiring ERCOT Approval

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

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| ***[NPRR857: Replace paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (1) Each TSP, DCTO, QSE, and Resource Entity shall coordinate with ERCOT the requirements of Section 3.10, Network Operations Modeling and Telemetry, the following types of work for any addition to, replacement of, or change to or removal from the ERCOT Transmission Grid: |

(a) Transmission lines;

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

(c) Resource interconnections; and

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

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| ***[NPRR1234: Insert paragraph (e) below upon system implementation:]***  (e) Large Load interconnections. |

**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.

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| ***[NPRR857 and NPRR1014: Replace applicable portions of paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities for NPRR857; and upon system implementation for NPRR1014:]***  (1) The energization or removal of a Transmission Facility, Generation Resource, or Energy Storage Resource (ESR) in the Network Operations Model requires an entry into the Outage Scheduler by a TSP, DCTO, or Resource Entity. For any TSP or DCTO request, the TSP or DCTO shall enter the request in the Outage Scheduler. For any Resource Entity request, the Resource Entity shall enter the request in the Outage Scheduler. If any changes in system topology or telemetry are expected, then the TSP, DCTO, or Resource Entity shall notify ERCOT in accordance with the schedule in Section 3.3.1, ERCOT Approval of New or Relocated Facilities. Information submitted pursuant to this subsection for Transmission Facilities within a Private Use Network shall not be publicly posted. |

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

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

(a) Proposed energize date;

(b) TSPs or Resource Entities performing work;

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

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

(e) Station identification code;

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

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

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

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

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

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

(l) Statement of completion, including:

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

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

(m) Drawings, including:

(i) Existing status;

(ii) Each intermediate stage; and

(iii) Proposed final configuration.

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| ***[NPRR857: Replace paragraph (3) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (3) Each TSP, DCTO, and Resource Entity shall submit any changes in system topology or telemetry in accordance with the Network Operations Model Change Request (NOMCR) process or other ERCOT-prescribed process applicable to Resource Entities and according to the requirements of Section 3.10.1, Time Line for Network Operations Model Changes. The submittal shall include the following:  (a) Proposed energize date;  (b) TSPs, DCTOs, or Resource Entities performing work;  (c) TSPs, DCTOs, or Resource Entities responsible for rating affected Transmission Element(s);  (d) For Resource Entities, data and information required by Section 16.5, Registration of a Resource Entity;  (e) Station identification code;  (f) Identification of existing Transmission Facilities involved and new Transmission Facilities (if any) being added or existing Transmission Facilities being permanently removed from service;  (g) Ratings of existing Transmission Facilities involved and new Transmission Facilities (if any) being added;  (h) Outages required (clearly identify each Outage if multiple Outages are required), including sequence of Outage and estimate of Outage duration;  (i) General statement of work to be completed with intermediate progress dates and events identified;  (j) SCADA modification work, including descriptions of the telemetry points or changes to existing telemetry, providing information on equipment being installed, changed, or monitored;  (k) Additional data determined by ERCOT, TSPs, DCTOs, or Resource Entities as needed to complete the ERCOT model representation of existing Transmission Facilities involved and new Transmission Facilities (if any) being added;  (l) Statement of completion, including:  (i) Statement to be made at the completion of each intermediate stage of project; and  (ii) Statement to be made at completion of total project.  (m) Drawings, including:  (i) Existing status;  (ii) Each intermediate stage; and  (iii) Proposed final configuration. |

**3.3.2.2 Record of Approved Work**

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

3.4 Load Zones

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

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

3.4.1 Load Zone Types

(1) The Load Zone types are:

(a) The Competitive Load Zones;

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

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

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

3.4.2 Load Zone Modifications

(1) Competitive Load Zones and NOIE Load Zones may be added, deleted, or changed, only when approved by the ERCOT Board, with the exception of paragraph (1)(c) of Section 3.4.3, NOIE Load Zones. Approved additions, deletions, or changes go into effect 48 months after the end of the month in which the addition, deletion, or change was approved, with the exception of paragraph (3) below. DC Tie Load Zones are not subject to these requirements.

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

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

3.4.3 NOIE Load Zones

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

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

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

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

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

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

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

3.4.4 DC Tie Load Zones

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

3.4.5 Additional Load Buses

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

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

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

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

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

(e) For each new Electrical Bus covered in paragraph (a) above and not covered in paragraph (d) above, ERCOT shall simulate LMPs for the annual peak hour of the system with the new Electrical Bus incorporated into the model. ERCOT shall assign each new Electrical Bus associated with a NOIE that is a part of a NOIE Load Zone to the Cost Allocation Zone with the closest matching zonal Settlement Point Price to the new Electrical Bus's LMP.

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

3.5 Hubs

3.5.1 Process for Defining Hubs

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

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

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

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

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

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| ***[NPRR857: Replace paragraph (5) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (5) If a Transmission Service Provider (TSP), Direct Current Tie Operator (DCTO), or ERCOT plans a nomenclature change in the Network Operations Model or the CRR Network Model, ERCOT shall file a NPRR to include the nomenclature change in the Hub Bus definitions before implementing the name change to either the Network Operations Model or the CRR Network Model. |

3.5.2 Hub Definitions

**3.5.2.1 North 345 kV Hub (North 345)**

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

|  | ERCOT Operations | |  |
| --- | --- | --- | --- |
| No. | Hub Bus | kV | Hub |
| 1 | ANASW | 345 | NORTH |
| 2 | CN345 | 345 | NORTH |
| 3 | WLSH | 345 | NORTH |
| 4 | FMRVL | 345 | NORTH |
| 5 | LPCCS | 345 | NORTH |
| 6 | MNSES | 345 | NORTH |
| 7 | PRSSW | 345 | NORTH |
| 8 | SSPSW | 345 | NORTH |
| 9 | VLSES | 345 | NORTH |
| 10 | ALNSW | 345 | NORTH |
| 11 | ALLNC | 345 | NORTH |
| 12 | BNDVS | 345 | NORTH |
| 13 | BNBSW | 345 | NORTH |
| 14 | BBSES | 345 | NORTH |
| 15 | BOSQUESW | 345 | NORTH |
| 16 | CDHSW | 345 | NORTH |
| 17 | CNTRY | 345 | NORTH |
| 18 | CRLNW | 345 | NORTH |
| 19 | CMNSW | 345 | NORTH |
| 20 | CNRSW | 345 | NORTH |
| 21 | CRTLD | 345 | NORTH |
| 22 | DCSES | 345 | NORTH |
| 23 | EMSES | 345 | NORTH |
| 24 | ELKTN | 345 | NORTH |
| 25 | ELMOT | 345 | NORTH |
| 26 | EVRSW | 345 | NORTH |
| 27 | KWASS | 345 | NORTH |
| 28 | FGRSW | 345 | NORTH |
| 29 | FORSW | 345 | NORTH |
| 30 | FRNYPP | 345 | NORTH |
| 31 | GIBCRK | 345 | NORTH |
| 32 | HKBRY | 345 | NORTH |
| 33 | VLYRN | 345 | NORTH |
| 34 | JEWET | 345 | NORTH |
| 35 | KNEDL | 345 | NORTH |
| 36 | KLNSW | 345 | NORTH |
| 37 | LCSES | 345 | NORTH |
| 38 | LIGSW | 345 | NORTH |
| 39 | LEG | 345 | NORTH |
| 40 | LFKSW | 345 | NORTH |
| 41 | LWSSW | 345 | NORTH |
| 42 | MLSES | 345 | NORTH |
| 43 | MCCREE | 345 | NORTH |
| 44 | MDANP | 345 | NORTH |
| 45 | ENTPR | 345 | NORTH |
| 46 | NCDSE | 345 | NORTH |
| 47 | NORSW | 345 | NORTH |
| 48 | NUCOR | 345 | NORTH |
| 49 | PKRSW | 345 | NORTH |
| 50 | KMCHI | 345 | NORTH |
| 51 | PTENN | 345 | NORTH |
| 52 | RENSW | 345 | NORTH |
| 53 | RCHBR | 345 | NORTH |
| 54 | RNKSW | 345 | NORTH |
| 55 | RKCRK | 345 | NORTH |
| 56 | RYSSW | 345 | NORTH |
| 57 | SGVSW | 345 | NORTH |
| 58 | SHBSW | 345 | NORTH |
| 59 | SHRSW | 345 | NORTH |
| 60 | SCSES | 345 | NORTH |
| 61 | SYCRK | 345 | NORTH |
| 62 | THSES | 345 | NORTH |
| 63 | TMPSW | 345 | NORTH |
| 64 | TNP\_ONE | 345 | NORTH |
| 65 | TRCNR | 345 | NORTH |
| 66 | TRSES | 345 | NORTH |
| 67 | TOKSW | 345 | NORTH |
| 68 | VENSW | 345 | NORTH |
| 69 | WLVEE | 345 | NORTH |
| 70 | W\_DENT | 345 | NORTH |
| 71 | WTRML | 345 | NORTH |
| 72 | WCSWS | 345 | NORTH |
| 73 | WEBBS | 345 | NORTH |
| 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. |

|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| ***[NPRR1007 and NPRR1057: Replace applicable portions of paragraph (4) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1057:]***  (4) The Real-Time Settlement Point Price of the Hub for a given 15-minute Settlement Interval is calculated as follows:  **RTSPP***North345* **= Max [-$251, (RTRDP +**  **(HUBLMP** *North345, y* **\* RNWF** *y***))]**  Where:  RTRDP = (RNWF *y* \* RTRDPA *y*)  RNWF *y* = TLMP *y* / TLMP *y*  The above variables are defined as follows:   |  |  |  | | --- | --- | --- | | **Variable** | **Unit** | **Description** | | RTSPP *North345* | $/MWh | *Real-Time Settlement Point Price*⎯The Real-Time Settlement Point Price at the Hub, for the 15-minute Settlement Interval. | | RTRDP | $/MWh | *Real-Time Reliability Deployment Price for Energy* ⎯The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that are calculated from the Real-Time Reliability Deployment Price Adder for Energy. | | RTRDPA *y* | $/MWh | *Real-Time Reliability Deployment Price Adder for Energy* ⎯The Real-Time Price Adder that captures the impact of reliability deployments on energy prices for the SCED interval *y.* | | RNWF *y* | none | *Resource Node Weighting Factor per interval*⎯The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval. | | HUBLMP*North345, y* | $/MWh | *Hub Locational Marginal Price*⎯The Hub LMP for the Hub for the SCED Interval *y*. | | TLMP *y* | second | *Duration of SCED interval per interval*⎯The duration of the portion of the SCED interval *y* within the 15-minute Settlement Interval | | *y* | none | A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval. | |

**3.5.2.2 South 345 kV Hub (South 345)**

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

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

|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| ***[NPRR1007 and NPRR1057: Replace applicable portions of paragraph (4) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1057:]***  (4) The Real-Time Settlement Point Price of the Hub for a given 15-minute Settlement Interval is calculated as follows:  **RTSPP** *South345* **= Max [-$251, (RTRDP +**  **(HUBLMP** *South345, y* **\* RNWF** *y***))]**  Where:  RTRDP = ( RNWF*y* \* RTRDPA*y*)  RNWF *y* = TLMP *y* / TLMP *y*  The above variables are defined as follows:   |  |  |  | | --- | --- | --- | | **Variable** | **Unit** | **Description** | | RTSPP *South345* | $/MWh | *Real-Time Settlement Point Price*⎯The Real-Time Settlement Point Price at the Hub, for the 15-minute Settlement Interval. | | RTRDP | $/MWh | *Real-Time Reliability Deployment Price for Energy*⎯The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that are calculated from the Real-Time Reliability Deployment Price Adder for Energy. | | RTRDPA *y* | $/MWh | *Real-Time Reliability Deployment Price Adder for Energy –*The Real-Time Price Adder that captures the impact of reliability deployments on energy prices for the SCED interval *y.* | | HUBLMP*South345, y* | $/MWh | *Hub Locational Marginal Price*⎯The Hub LMP for the Hub for the SCED Interval *y*. | | RNWF *y* | none | *Resource Node Weighting Factor per interval*⎯The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval. | | TLMP *y* | second | *Duration of SCED interval per interval*⎯The duration of the portion of the SCED interval *y* within the 15-minute Settlement Interval. | | *y* | none | A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval. | |

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

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

|  | 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. |

|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| ***[NPRR1007 and NPRR1057: Replace applicable portions of paragraph (4) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1057:]***  (4) The Real-Time Settlement Point Price of the Hub for a given 15-minute Settlement Interval is calculated as follows:  **RTSPP** *Houston345* **= Max [-$251, (RTRDP +**  **(HUBLMP** *Houston345, y* **\* RNWF** *y* **))]**  Where:  RTRDP = (RNWF *y* \* RTRDPA *y*)  RNWF *y* = TLMP *y* / TLMP *y*  The above variables are defined as follows:   | **Variable** | **Unit** | **Description** | | --- | --- | --- | | RTSPP *Houston345* | $/MWh | *Real-Time Settlement Point Price*⎯The Real-Time Settlement Point Price at the Hub, for the 15-minute Settlement Interval. | | RTRDP | $/MWh | *Real-Time Reliability Deployment Price for Energy* ⎯The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that are calculated from the Real-Time Reliability Deployment Price Adder for Energy. | | RTRDPA *y* | $/MWh | *Real-Time Reliability Deployment Price Adder for Energy* ⎯The Real-Time Price Adder that captures the impact of reliability deployments on energy prices for the SCED interval *y.* | | HUBLMP*Houston345, y* | $/MWh | *Hub Locational Marginal Price*⎯The Hub LMP for the Hub for the SCED Interval *y*. | | RNWF *y* | none | *Resource Node Weighting Factor per interval*⎯The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval. | | TLMP *y* | second | *Duration of SCED interval per interval*⎯The duration of the portion of the SCED interval *y* within the 15-minute Settlement Interval | | *y* | none | A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval. | |

**3.5.2.4 West 345 kV Hub (West 345)**

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

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

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

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

**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. |

|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| ***[NPRR1007 and NPRR1057: Replace applicable portions of paragraph (4) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation of NPRR1057:]***  (4) The Real-Time Settlement Point Price of the Hub for a given 15-minute Settlement Interval is calculated as follows:  **RTSPP** *West345* **= Max [-$251, (RTRDP +**  **(HUBLMP** *West345, y* **\* RNWF** *y***))]**  Where:  RTRDP = (RNWF *y* \* RTRDPA *y*)  RNWF *y* = TLMP *y* / TLMP *y*  The above variables are defined as follows:   | **Variable** | **Unit** | **Description** | | --- | --- | --- | | RTSPP *West345* | $/MWh | *Real-Time Settlement Point Price*⎯The Real-Time Settlement Point Price at the Hub, for the 15-minute Settlement Interval. | | RTRDP | $/MWh | *Real-Time Reliability Deployment Price for Energy*⎯The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that are calculated from the Real-Time Reliability Deployment Price Adder for Energy. | | RTRDPA *y* | $/MWh | *Real-Time Reliability Deployment Price Adder for Energy*⎯The Real-Time Price Adder that captures the impact of reliability deployments on energy prices for the SCED interval *y.* | | HUBLMP*West345, y* | $/MWh | *Hub Locational Marginal Price*⎯The Hub LMP for the Hub for the SCED Interval *y*. | | RNWF *y* | none | *Resource Node Weighting Factor per interval*⎯The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval. | | TLMP *y* | second | *Duration of SCED interval per interval*⎯The duration of the portion of the SCED interval *y* within the 15-minute Settlement Interval. | | *y* | none | A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval. | |

**3.5.2.5 Panhandle 345 kV Hub (Pan 345)**

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

|  |  |  |  |
| --- | --- | --- | --- |
|  | ERCOT Operations | |  |
| No. | Hub Bus | kV | Hub |
| 1 | ABERNATH | 345 | PAN |
| 2 | AJ\_SWOPE | 345 | PAN |
| 3 | ALIBATES | 345 | PAN |
| 4 | CTT\_CROS | 345 | PAN |
| 5 | CTT\_GRAY | 345 | PAN |
| 6 | OGALLALA | 345 | PAN |
| 7 | RAILHEAD | 345 | PAN |
| 8 | TESLA | 345 | PAN |
| 9 | TULECNYN | 345 | PAN |
| 10 | W\_CW\_345 | 345 | PAN |
| 11 | WHIT\_RVR | 345 | PAN |
| 12 | WINDMILL | 345 | PAN |

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

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

**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. |

|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| ***[NPRR1007 and NPRR1057: Replace applicable portions of paragraph (4) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1057:]***  (4) The Real-Time Settlement Point Price of the Hub for a given 15-minute Settlement Interval is calculated as follows:  **RTSPP** *Pan345* **= Max [-$251, (RTRDP +**  **(HUBLMP** *Pan345, y* **\* RNWF** *y* **))]**  Where:  RTRDP =  (RNWF *y* \* RTRDPA *y*)  RNWF *y* = TLMP *y* / TLMP *y*  The above variables are defined as follows:   | **Variable** | **Unit** | **Description** | | --- | --- | --- | | RTSPP *Pan345* | $/MWh | *Real-Time Settlement Point Price*⎯The Real-Time Settlement Point Price at the Hub for the 15-minute Settlement Interval. | | RTRDP | $/MWh | *Real-Time Reliability Deployment Price for Energy*⎯The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that are calculated from the Real-Time Reliability Deployment Price Adder for Energy. | | RTRDPA *y* | $/MWh | *Real-Time Reliability Deployment Price Adder for Energy*⎯The Real-Time Price Adder that captures the impact of reliability deployments on energy prices for the SCED interval *y.* | | HUBLMP*Pan345, y* | $/MWh | *Hub Locational Marginal Price*⎯The Hub LMP for the Hub for the SCED Interval *y*. | | RNWF *y* | none | *Resource Node Weighting Factor per interval*⎯The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval. | | TLMP *y* | second | *Duration of SCED interval per interval*⎯The duration of the portion of the SCED interval *y* within the 15-minute Settlement Interval. | | *y* | none | A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval. | |

|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| ***[NPRR941, NPRR1007, and NPRR1057: Insert applicable portions of Section 3.5.2.6 below upon system implementation for NPRR941 or NPRR1057; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; and renumber accordingly:]***  **3.5.2.6 Lower Rio Grande Valley Hub (LRGV 138/345)**  (1) The Lower Rio Grande Valley Hub 138/345 kV Hub is composed of the following listed Hub Buses:   |  |  |  |  | | --- | --- | --- | --- | |  | ERCOT Operations |  |  | | No. | Hub Bus | kV | Hub | | 1 | AIRPORT | 138 | LRGV | | 2 | ALBERTA | 138 | LRGV | | 3 | BATES | 138 | LRGV | | 4 | FRONTERA | 138 | LRGV | | 5 | GARZA | 138 | LRGV | | 6 | HARLNSW | 138 | LRGV | | 7 | HEC | 138 | LRGV | | 8 | KEY\_SW | 138 | LRGV | | 9 | LA\_PALMA\_345 | 345 | LRGV | | 10 | LA\_PALMA\_138 | 138 | LRGV | | 11 | LASPULGA | 138 | LRGV | | 12 | LISTON | 138 | LRGV | | 13 | LOMA\_ALT | 138 | LRGV | | 14 | MARCONI | 138 | LRGV | | 15 | MILHWY | 138 | LRGV | | 16 | MILITARY | 138 | LRGV | | 17 | MV\_WEDN4 | 138 | LRGV | | 18 | N\_MCALLN | 138 | LRGV | | 19 | NEDIN\_345 | 345 | LRGV | | 20 | NEDIN\_138 | 138 | LRGV | | 21 | OLEANDER | 138 | LRGV | | 22 | P\_ISABEL | 138 | LRGV | | 23 | PALMHRTP | 138 | LRGV | | 24 | PALMITO\_345 | 345 | LRGV | | 25 | PALMITO\_138 | 138 | LRGV | | 26 | PAREDES | 138 | LRGV | | 27 | PHARMVEC | 138 | LRGV | | 28 | PHARR | 138 | LRGV | | 29 | PRICE\_RD | 138 | LRGV | | 30 | RAILROAD | 138 | LRGV | | 31 | RAYMND2 | 138 | LRGV | | 32 | REDTAP | 138 | LRGV | | 33 | RIO\_GRAN | 138 | LRGV | | 34 | RIOHONDO\_345 | 345 | LRGV | | 35 | RIOHONDO\_138 | 138 | LRGV | | 36 | ROMA\_SW | 138 | LRGV | | 37 | S\_MCALLN | 138 | LRGV | | 38 | SCARBIDE | 138 | LRGV | | 39 | SILASRAY | 138 | LRGV | | 40 | STEWART | 138 | LRGV | | 41 | WESLACO | 138 | LRGV |   (2) The Lower Rio Grande Valley 138/345 kV Hub Price uses the aggregated Shift Factors of the Hub Buses for each hour of the Settlement Interval of the DAM in the Day-Ahead and is the simple average of the time weighted Hub Bus prices for each 15-minute Settlement Interval in Real-Time, for each Hub Bus included in this Hub.  (3) The Day-Ahead Settlement Point Price of the Hub for a given Operating Hour is calculated as follows:  **DASPP** *LRGV 138/345* **= DASL – (DAHUBSF***LRGV 138/345, c***\* DASP** *c***),**  **if HBBC***LRGV138/345***≠0**  **DASPP** *LRGV138/345* **= DASPP** *ERCOT345Bus***, if HBBC***LRGV138/345***=0**  Where:  DAHUBSF *LRGV138/345, c =* (HUBDF *hb, LRGV138/345, c* \* DAHBSF *hb, LRGV138/345, c*)  DAHBSF *hb, LRGV138/345, c =* (HBDF *pb, hb, LRGV138/345, c* \* DASF *pb, hb, LRGV138/345, c*)  HUBDF *hb, LRGV138/345, c =* IF(HB*LRGV138/345, c*=0, 0, 1 **/** HB *LRGV138/345, c*)  HBDF *pb, hb, LRGV138/345, c =* IF(PB*hb, LRGV138/345, c*=0, 0, 1 **/** PB *hb, LRGV138/345, c*)  The above variables are defined as follows:   | Variable | Unit | Definition | | --- | --- | --- | | DASPP *LRGV138/345* | $/MWh | *Day-Ahead Settlement Point Price*⎯The DAM Settlement Point Price at the Hub, for the hour. | | DASL | $/MWh | *Day-Ahead System Lambda*⎯The DAM Shadow Price for the system power balance constraint for the hour. | | DASP *c* | $/MWh | *Day-Ahead Shadow Price for a binding transmission constraint*⎯The DAM Shadow Price for the constraint *c* for the hour. | | DAHUBSF *LRGV138/345,c* | none | *Day-Ahead Shift Factor of the Hub ⎯*The DAM aggregated Shift Factor of a Hub for the constraint *c* for the hour. | | DAHBSF *hb, LRGV138/345,c* | none | *Day-Ahead Shift Factor of the Hub Bus⎯*The DAM aggregated Shift Factor of a Hub Bus *hb* for the constraint *c* for the hour. | | DASF *pb,hb, LRGV138/345,c* | none | *Day-Ahead Shift Factor of the power flow bus⎯*The DAM Shift Factor of a power flow bus *pb* that is a component of Hub Bus *hb* for the constraint *c* for the hour. | | HUBDF *hb, LRGV138/345,c* | none | *Hub Distribution Factor per Hub Bus in a constraint*⎯The distribution factor of Hub Bus *hb* for the constraint *c* for the hour. | | HBDF *pb, hb, LRGV138/345,c* | none | *Hub Bus Distribution Factor per power flow bus of Hub Bus in a constraint*⎯The distribution factor of power flow bus *pb* that is a component of Hub Bus *hb* for the constraint *c* for the hour. | | *pb* | none | An energized power flow bus that is a component of a Hub Bus for the constraint *c*. | | PB *hb, LRGV138/345,c* | none | The total number of energized power flow buses in Hub Bus *hb* for the constraint *c*. | | *hb* | none | A Hub Bus that is a component of the Hub with at least one energized power flow bus for the constraint *c*. | | HBBC *LRGV138/345* | none | The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus in base case. | | HB *LRGV138/345,c* | none | The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus for the constraint *c*. | | *c* | none | A DAM binding transmission constraint for the hour caused by either base case or a contingency. |   (4) The Real-Time Settlement Point Price of the Hub for a given 15-minute Settlement Interval is calculated as follows:  **RTSPP** *LRGV138/345* **= Max [-$251, (RTRDP +**  **(HUBLMP** *LRGV138/345, y* **\* RNWF** *y***))]**  Where:  RTRDP = (RNWF *y* \* RTRDPA *y*)  RNWF *y* = TLMP *y* / TLMP *y*  The above variables are defined as follows:   | **Variable** | **Unit** | **Description** | | --- | --- | --- | | RTSPP *LRGV138/345kV* | $/MWh | *Real-Time Settlement Point Price*⎯The Real-Time Settlement Point Price at the Hub for the 15-minute Settlement Interval. | | RTRDP | $/MWh | *Real-Time Reliability Deployment Price for Energy*⎯The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that are calculated from the Real-Time Reliability Deployment Price Adder for Energy. | | RTRDPA *y* | $/MWh | *Real-Time Reliability Deployment Price Adder for Energy*⎯The Real-Time Price Adder that captures the impact of reliability deployments on energy prices for the SCED interval *y.* | | HUBLMP*LRGV138/345, y* | $/MWh | *Hub Locational Marginal Price*⎯The Hub LMP for the Hub for the SCED Interval *y*. | | RNWF *y* | none | *Resource Node Weighting Factor per interval*⎯The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval. | | TLMP *y* | second | *Duration of SCED interval per interval*⎯The duration of the portion of the SCED interval *y* within the 15-minute Settlement Interval. | | *y* | none | A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval. | |

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

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

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| ***[NPRR941: Replace paragraph (1) above upon system implementation:]***  (1) The ERCOT Hub Average 345 kV Hub price for Day-Ahead is calculated for each hour using the aggregated Shift Factors of four Hubs: the North 345 kV Hub, the South 345 kV Hub, the Houston 345 kV Hub, and the West 345 kV Hub. The ERCOT Hub Average 345 kV Hub price for Real-Time is the simple average of four prices from the applicable time period: the North 345 kV Hub price, the South 345 kV Hub price, the Houston 345 kV Hub price, and the West 345 kV Hub price. The Panhandle 345 kV Hub and the Lower Rio Grande Valley 138/345 kV Hub are not included in either the Day-Ahead or Real-Time ERCOT Hub Average 345 kV Hub price. |

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

**DASPP *ERCOT345* = DASL – (DAHUBSF*ERCOT345, c* \* DASP *c*),**

**if HBBC*ERCOT345Bus*≠0**

**DASPP *ERCOT345* = DASPP *ERCOT345Bus*, if HBBC *ERCOT345Bus*=0**

Where:

DAHUBSF *ERCOT345, c =* (DAHUBSF *North345, c* + DAHUBSF *South345, c* +

DAHUBSF *Houston345, c* + DAHUBSF *West345, c*) / 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. |
| 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 *ERCOT345,c* | none | *Day-Ahead Shift Factor of ERCOT 345 ⎯*The DAM aggregated Shift Factor of ERCOT 345 Hub for the constraint *c* for the hour. |
| DAHUBSF *North345,c* | none | *Day-Ahead Shift Factor of North 345⎯*The DAM aggregated Shift Factor of the North 345 Hub for the constraint *c* for the hour. |
| DAHUBSF *South345,c* | none | *Day-Ahead Shift Factor of South 345⎯*The DAM aggregated Shift Factor of the South 345 Hub for the constraint *c* for the hour. |
| DAHUBSF *Houston345,c* | none | *Day-Ahead Shift Factor of Houston 345⎯*The DAM aggregated Shift Factor of the Houston 345 Hub for the constraint *c* for the hour. |
| DAHUBSF *West345,c* | none | *Day-Ahead Shift Factor of West 345⎯*The DAM aggregated Shift Factor of the West 345 Hub for the constraint *c* for the hour. |
| 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”. |
| *c* | none | A DAM binding transmission constraint for the hour caused by either base case or a contingency. |

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

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. |

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

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

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| ***[NPRR941: Replace paragraph (1) above upon system implementation:]***  (1) The ERCOT Bus Average 345 kV Hub is composed of the Hub Buses listed in Section 3.5.2.1, North 345 kV Hub (North 345); Section 3.5.2.2, South 345 kV Hub (South 345); Section 3.5.2.3, Houston 345 kV Hub (Houston 345); and Section 3.5.2.4, West 345 kV Hub (West 345). The Panhandle 345 kV Hub and the Lower Rio Grande Valley 138/345 kV Hub are not included in the ERCOT Bus Average 345 kV Hub price. |

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

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

**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.” |

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| ***[NPRR1007 and NPRR1057: Replace applicable portions of paragraph (4) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1057:]***  (4) The Real-Time Settlement Point Price of the Hub for a given 15-minute Settlement Interval is calculated as follows:  **RTSPP** *ERCOT345Bus* **= Max [-$251, (RTRDP +** **(HUBLMP*ERCOT345Bus,y* \* RNWF *y*))]**  Where:  RTRDP = (RNWF *y* \* RTRDPA *y*)  RNWF *y* = TLMP *y* / TLMP *y*  The above variables are defined as follows:   | **Variable** | **Unit** | **Description** | | --- | --- | --- | | RTSPP *ERCOT345Bus* | $/MWh | *Real-Time Settlement Point Price*⎯The Real-Time Settlement Point Price at the Hub, for the 15-minute Settlement Interval. | | RTRDP | $/MWh | *Real-Time Reliability Deployment Price for Energy*⎯The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that are calculated from the Real-Time Reliability Deployment Price Adder for Energy. | | RTRDPA *y* | $/MWh | *Real-Time Reliability Deployment Price Adder for Energy*⎯The Real-Time Price Adder that captures the impact of reliability deployments on energy prices for the SCED interval *y.* | | HUBLMP *ERCOT345Bus,y* | $/MWh | *Hub Locational Marginal Price for the ERCOT345Bus*⎯The Hub LMP for the ERCOT Bus Average 345 kV Hub (ERCOT 345 Bus), for the SCED Interval *y*. | | RNWF *y* | none | *Resource Node Weighting Factor per interval*⎯The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval. | | TLMP *y* | second | *Duration of SCED interval per interval*⎯The duration of the portion of the SCED interval *y* within the 15-minute Settlement Interval. | | *y* | none | A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval. | |

3.5.3 ERCOT Responsibilities for Managing Hubs

**3.5.3.1 Posting of Hub Buses and Electrical Buses included in Hubs**

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

**3.5.3.2 Calculation of Hub Prices**

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

3.6 Load Participation

***3.6.1 Load Resource Participation***

(1) A Load Resource may participate by providing:

(a) Ancillary Service:

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

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

(iii) Responsive Reserve (RRS) as a CLR 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;

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

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| ***[NPRR1244: Replace paragraph (iv) above with the following upon system implementation:]***  (iv) ERCOT Contingency Reserve Service (ECRS) as a CLR qualified for SCED Dispatch, or as a Load Resource that may or may not be controlled by high-set under-frequency relay; |

(v) Non-Spinning Reserve (Non-Spin) as a CLR qualified for SCED Dispatch or as a Load Resource that is not a CLR and that is not controlled by under-frequency relay; and

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

(b) Energy in the form of Demand response from a CLR 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

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| ***[NPRR1007: Replace paragraph (c) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (c) Emergency Response Service (ERS) for hours in which the Load Resource has a Resource Status of OUTL; and |

(d) Voluntary Load response in Real-Time.

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

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

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

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

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| ***[NPRR1188 and NPRR1246: Replace applicable portions of paragraph (5) above with the following upon system implementation for NPRR1188; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1246:]***  (5) The Settlement Point for a CLR that is not an ALR is its Resource Node Settlement Point. The Settlement Point for an ALR is its Load Zone Settlement Point. |

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

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

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

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

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

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

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

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

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

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

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

3.6.2 Decision Making Entity for a Resource

(1) Each Resource Entity that owns a Resource, except for a Load Resource that is not SCED qualified, shall submit a declaration to ERCOT, using Section 23, Form C, Managed Capacity Declaration, as to which Decision Making Entity (DME) has control of each of its Resources. The declaration shall be signed by the Authorized Representative of the Resource Entity. In addition, each Resource Entity that owns a Resource, except for a Load Resource that is not SCED qualified, shall notify ERCOT of any known changes in that declaration no later than 14 days prior to the date that the change takes effect, or as soon as possible in a situation where the Resource Entity is unable to meet the 14-day Notice requirement. However, in no event may the Resource Entity inform ERCOT later than 72 hours before the date on which the change in DME takes effect. Upon ERCOT’s request, each Resource Entity that owns a Resource, except for a Load Resource that is not SCED qualified, shall provide ERCOT with sufficient information or documentation to verify the DME’s control of the Resource. ERCOT shall update the DME for a Resource effective the first Operating Hour of the Operating Day after ERCOT satisfactorily confirms the Resource Entity’s most recent declaration, but not sooner than the effective date specified on the Resource Entity’s most recent declaration.

3.7 Resource Parameters

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

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| ***[NPRR995: Replace paragraph (1) above with the following upon system implementation:]***  (1) A Resource Entity shall register its Generation Resources, Energy Storage Resources (ESRs), Settlement Only Generators (SOGs), Settlement Only Energy Storage Systems (SOESSs), and Load Resources pursuant to Planning Guide Section 6.8, Resource Registration Procedures. The Resource Parameters, listed in Section 3.7.1, Resource Parameter Criteria, are a subset of Resource Registration data defined in the Resource Registration Glossary. |

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

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

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

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

3.7.1 Resource Parameter Criteria

**3.7.1.1 Generation Resource Parameters**

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

(a) Normal Ramp Rate curve;

(b) Emergency Ramp Rate curve;

(c) Minimum On-Line time;

(d) Minimum Off-Line time;

(e) Maximum On-Line time;

(f) Maximum daily starts;

(g) Maximum weekly starts;

(h) Maximum weekly energy;

(i) Hot start time;

(j) Intermediate start time;

(k) Cold start time;

(l) Hot to intermediate time; and

(m) Intermediate to cold time.

**3.7.1.2 Load Resource Parameters**

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

(a) Maximum interruption time;

(b) Maximum daily deployments;

(c) Maximum weekly deployments;

(d) Maximum weekly energy;

(e) Minimum notice time;

(f) Minimum interruption time; and

(g) Minimum restoration time.

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

(a) Normal Ramp Rate curve;

(b) Emergency Ramp Rate curve;

(c) Maximum deployment time; and

(d) Maximum weekly energy.

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

**3.7.1.3 Energy Storage Resource Parameters**

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

(a) Normal Ramp Rate curve; and

(b) Emergency Ramp Rate curve.

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| ***[NPRR1204: Insert paragraph (c) below upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (c) Round Trip Efficiency. |

***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

### 3.8.1 Split Generation Resources

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

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

(d) Within five Business Days, notify all other QSEs that represent the Split Generation Resource when the Resource received a High Dispatch Limit (HDL) override instruction.

(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.

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| ***[NPRR1007: Replace paragraph (7) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (7) Each QSE representing a Split Generation Resource may independently submit Energy Offer Curves, Ancillary Service Offers, and Three-Part Supply Offers. ERCOT shall treat each Split Generation Resource offer as a separate offer, except that all Split Generation Resources in a single Generation Resource must be committed or decommitted together. |

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

3.8.2 Combined Cycle Generation Resources

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

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| ***[NPRR1007: Replace paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (1) ERCOT shall assign a logical Resource Node for use in the Day-Ahead Market (DAM), RUC, Security-Constrained Economic Dispatch (SCED) and Load Frequency Control (LFC) to each registered Combined Cycle Train. Each Combined Cycle Generation Resource registered in the Combined Cycle Train will be mapped to the Combined Cycle Train logical Resource Node for the purposes of evaluating and settling each Combined Cycle Generation Resource’s Three-Part Supply Offer and Ancillary Service Offer in the DAM, RUC and SCED. Each generation unit identified in the Combined Cycle Train registration for a Combined Cycle Generation Resource configuration will be mapped to its designated Resource Node as determined in accordance with these Protocols and the Other Binding Document titled “Procedure for Identifying Resource Nodes.” |

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

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

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

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

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

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

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

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

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

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

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

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| ***[NPRR1007: Replace paragraph (6) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (6) For Ancillary Services offered and provided from Combined Cycle Generation Resources, ERCOT shall apply, without exception, the same rules and requirements specified in these Protocols for the DAM, RUC and Adjustment Period and Real-Time markets that apply to Ancillary Services provided from any other Generation Resources.  (a) ERCOT systems shall determine the operating limits for a Combined Cycle Generation Resource as follows:  (i) In Real-Time, relative to the telemetered capacity limits, ramp rates, and Ancillary Service capabilities for the Combined Cycle Generation Resource;  (ii) During the DAM study period, relative to the HSL in the COP; or  (iii) During the RUC Study Period, relative to the capacity limits and Ancillary Service capabilities in the COP. |

3.8.3 Quick Start Generation Resources

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

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| ***[NPRR1007: Replace paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (1) The QSE for a Quick Start Generation Resource (QSGR) that is available for deployment by SCED and awarding of ERCOT Contingency Reserve Service (ECRS) and Non-Spinning Reserve (Non-Spin), if qualified and capable, shall set the COP Resource Status to OFFQS, and the COP Low Sustained Limit (LSL) and COP HSL values to the expected sustainable LSL and HSL for the QSGR for the hour. |

(2) The QSGR that is available for deployment by SCED shall telemeter a Resource Status of OFFQS and a LSL of zero prior to receiving a deployment instruction from SCED. This status is necessary in order for SCED to recognize that the Resource can be Dispatched. The status of the breaker shall be open and the output of the Resource shall be zero in order for the State Estimator to correctly assess the state of the system. After being deployed for energy from SCED, the Resource shall telemeter an LSL equal to or less than the Resource’s actual output until the Resource has ramped to its physical LSL. After reaching its physical LSL, the QSGR shall telemeter an LSL that reflects its physical LSL. The QSGR that is providing Off-Line Non-Spin shall always telemeter an Ancillary Service Resource Responsibility for Non-Spin to reflect the Resource’s Non-Spin obligation and shall always telemeter an Ancillary Service Schedule for Non-Spin of zero to make the capacity available for SCED.

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| ***[NPRR1007: Replace paragraph (2) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (2) The QSGR that is available for deployment by SCED and awarding of ECRS and Non-Spin, if qualified and capable, shall telemeter a Resource Status of OFFQS and a LSL of zero prior to receiving a deployment instruction from SCED. This status is necessary in order for SCED to recognize that the Resource can be Dispatched and/or awarded ECRS and Non-Spin. The status of the breaker shall be open and the output of the Resource shall be zero in order for the State Estimator to correctly assess the state of the system. After being deployed for energy from SCED, the Resource shall telemeter an LSL equal to or less than the Resource’s actual output until the Resource has ramped to its physical LSL. After reaching its physical LSL, the QSGR shall telemeter an LSL that reflects its physical LSL. |

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

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

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

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| ***[NPRR1007: Replace paragraph (5) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (5) For a QSGR that is physically Off-Line, the Resource Entity shall submit a Normal Ramp Rate curve and Emergency Ramp Rate curve indicating QSGR’s ability to reach its ten-minute tested output from zero output in five minutes. This is necessary to prevent SCED from deploying multiple QSGRs due to ramp limitation in the first five minutes after being Dispatched by SCED. QSGRs shall be exempt from Set Point Deviation Charges as described in Section 6.6.5.3, Resources Exempt from Deviation Charges. |

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

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

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

3.8.3.1 Quick Start Generation Resource Decommitment Decision Process

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

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

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

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

3.8.4 Generation Resources Operating in Synchronous Condenser Fast-Response Mode

(1) A QSE is considered to have performed for the amount of its RRS obligation for the MW amount provided by a Generation Resource operating in synchronous condenser fast-response mode and triggered by an under-frequency relay device at the frequency set point specified in paragraph (3)(c) of Section 3.18, Resource Limits in Providing Ancillary Service, without corresponding RRS deployment by ERCOT. This provision applies only for the duration when RRS MW is deployed by automatic under-frequency relay action.

3.8.5 Energy Storage Resources

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

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| ***[NPRR1246: Delete paragraph (1) above upon system implementation of the Real-Time Co-Optimization (RTC) project and renumber accordingly.]*** |

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

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

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

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| ***[NPRR1075: Replace paragraph (3) above with the following upon system implementation of NPRR1014:]***  (3) A QSE representing an ESR may update the telemetered HSL and/or LSL for the ESR in Real-Time to reflect state of charge limitations. |

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

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| ***[NPRR1075: Replace paragraph (4) above with the following upon system implementation of NPRR1014:]***  (4) A QSE representing an ESR co-located with a Generation Resource may update the telemetered LSL of the ESR when self-charging (using output from the Generation Resource). The updated LSL shall be equal to the MW level of self-charge. |

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

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

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

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

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

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

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

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| ***[NPRR1171 and NPRR1213: Replace paragraph (1) above with the following upon system implementation for NPRR1171; or upon system implementation and upon system implementation of NPRR1171 for NPRR1213, and renumber accordingly:]***  (1) As a condition for the interconnection of a DGR or DESR, the affected Resource Entity, after consultation with the relevant Distribution Service Provider (DSP), shall submit an executed Section 23, Form R, Interconnection Circuit Designation for Distribution Generation Resources (DGRs) and Distribution Energy Storage Resources (DESRs).  (a) The DSP shall indicate that the interconnecting distribution circuit for the DGR or DESR is subject to Load shed if the DSP determines that the distribution circuit may be disconnected as part of an Energy Emergency Alert (EEA) Level 3 Load shedding event, an Under-Frequency Load Shed (UFLS) event, or an Under-Voltage Load Shed (UVLS) event.  (b) The DSP shall indicate that the interconnecting distribution circuit for the DGR or DESR is not subject to Load shed if the DSP determines that the distribution circuit will not be disconnected for any Load shed purpose during any of the events listed in paragraph (a) above. This condition may be met where:  (i) A DGR or DESR is connected to a distribution circuit which the DSP has excluded from Load shedding events, which may include, but is not limited to, a distribution circuit that interconnects only DGRs or DESRs; or  (ii) A DGR or DESR is connected to a distribution circuit where a recloser or other sectionalizing device excludes the DGR or DESR from Load shedding events on the distribution circuit.  (c) If the DSP has indicated that the interconnecting distribution circuit may be subject to Load shed, the DGR or DESR may qualify to provide only the following Ancillary Services, subject to the limits established by ERCOT pursuant to Section 3.16, Standards for Determining Ancillary Service Quantities:  (i) Non-Spinning Reserve (Non-Spin);  (ii) ERCOT Contingency Reserve Service (ECRS); and  (iii) Regulation Down Service (Reg-Down).  (d) If the DSP has indicated that the interconnecting distribution circuit is not subject to Load shed, then the DGR or DESR shall not be subject to the Ancillary Service qualification limitations described in paragraph (c) above.  (e) The DSP shall identify on Section 23, Form R, whether the DSP has identified any operational limitations for the DGR or DESR based on known system limitations and planning or operational studies, including studies performed in accordance with Planning Guide Section 5.4.2, Submission of Interconnection Agreement and TSP and/or DSP Studies and Technical Requirements. Temporary limitations, such as may occur during maintenance outage conditions, are not required to be reported on Section 23, Form R.  (2) If a DSP at any time after the interconnection of a DGR or DESR determines that any circuit to which the DGR or DESR is interconnected will be subject to Load shed during any of the Load shedding events listed in paragraph (1)(a) above, or that a DGR or DESR will need to be electrically relocated to a circuit that will be subject to Load shed during these Load shedding events:  (a) The DSP shall promptly notify ERCOT and the designated contact for the DGR or DESR;  (b) The Resource Entity for the DGR or DESR shall promptly submit an updated Section 23, Form R, to ERCOT and shall make a corresponding update to its Resource Registration data; and  (c) The Ancillary Service qualification limitations in paragraph (1)(c) above will apply to the DGR or DESR.  (3) If a DGR or DESR is interconnected to a circuit that is subject to Load shed and then either is relocated to a different circuit that is not subject to Load shed during any of the Load shed events listed in paragraph (1)(a) above or receives notification from the DSP that the DGR or DESR is no longer subject to Load shed during any of these events, the Resource Entity for the DGR or DESR shall submit an updated Section 23, Form R, to ERCOT and shall make a corresponding update to its Resource Registration data. |

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

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| ***[NPRR995 and NPRR1171: Replace applicable portions of paragraph (2) above with the following upon system implementation:]***  (2) For a proposed conversion of an existing Settlement Only Distribution Generator (SODG) to a DGR or for a proposed conversion of an existing Settlement Only Distribution Energy Storage System (SODESS) to a DESR, the Resource Entity will follow the generation interconnection process outlined in Planning Guide Section 5, Generator Interconnection or Modification. |

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

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

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

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

***3.8.7 Self-Limiting Facility***

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

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| ***[NPRR1077: Replace paragraph (1) above with the following upon system implementation:]***  (1) A Resource Entity or Interconnecting Entity (IE) for a Self-Limiting Facility may establish a MW Injection or MW Withdrawal limit by submitting an attestation in a form designated by ERCOT through the Resource Registration process. The Resource Entity or IE shall simultaneously provide a copy of the attestation to the interconnecting Transmission and/or Distribution Service Provider (TDSP). All registered generators or Energy Storage Resources (ESRs) within a Self-Limiting Facility shall be represented by a single Resource Entity and a single QSE. |

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

(3) On a monthly basis, ERCOT will report to the Reliability Monitor and IMM any instance where a Self-Limiting Facility’s actual MW Injections exceeded the MW Injection limit or where actual MW Withdrawals exceeded the MW Withdrawal limit established in the Resource Registration data for the Self-Limiting Facility, as described in Section 3.9.1, Current Operating Plan (COP) Criteria.

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| ***[NPRR1077: Replace paragraph (3) above with the following upon system implementation:]***  (3) On a monthly basis, ERCOT will report to the Reliability Monitor and IMM any instance where a Self-Limiting Facility’s actual MW Injections exceeded the MW Injection limit or where actual MW Withdrawals exceeded the MW Withdrawal limit established in the Resource Registration data for the Self-Limiting Facility, based on the telemetry of the injection and withdrawal values provided by the QSE for the registered generator or ESS in the Self-Limiting Facility, as described in Section 3.9.1, Current Operating Plan (COP) Criteria, and in Section 6.5.5.2, Operational Data Requirements, or based on the meter data at the Point of Interconnection (POI) or Point of Common Coupling (POCC) for the Self-Limiting Facility. |

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

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

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

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| ***[NPRR1077: Replace paragraph (6) above with the following upon system implementation:]***  (6) A Distribution Service Provider (DSP) may limit injections and withdrawals from any Generation Resource, Settlement Only Generator (SOG), or ESR based on Resource Registration data and the interconnection agreement between the DSP and the IE or Resource Entity. In that case, the IE or Resource Entity shall submit the attestation required by paragraph (1) above, and shall be considered a Self-Limiting Facility. |

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

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

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| ***[NPRR1029: Insert Section 3.8.8 below upon system implementation:]***  ***3.8.8 DC-Coupled Resources***  (1) A DC-Coupled Resource shall be treated in the same manner as an Energy Storage Resource (ESR) for the purposes of determining Set Point Deviation Charges, as described in Section 6.6.5, Set Point Deviation Charge, and Energy Storage Resource Energy Deployment Performance (ESREDP), as described in Section 8.1.1.4.1, Regulation Service and Generation Resource/Controllable Load Resource/Energy Storage Resource Energy Deployment Performance, and Ancillary Service Capacity Performance Metrics, under one of the following conditions:  (a) The Resource was awarded Ancillary Service;  (b) The Resource’s instantaneous MW Injection or MW Withdrawal includes non-zero MW from the ESS component of the DC-Coupled Resource; or  (c) The Resource’s telemetered HSL or LSL includes the ESS capability.  (2) At all other times, a DC-Coupled Resource shall be treated in the same manner as an IRR for the purposes of determining Set Point Deviation Charges, as described in Section 6.6.5, and ESREDP, as described in Section 8.1.1.4.1.  (3) A QSE representing a DC-Coupled Resource that does not meet any of the conditions in paragraph (1) above:  (a) Shall set the Resource’s telemetered HSL equal to the current net output capability of the intermittent renewable generation component of the DC-Coupled Resource; and  (b) Shall set the Resource’s output at or below the SCED Base Point telemetered by ERCOT if the Resource receives a flag indicating that SCED has dispatched it below the Resource’s HDL used by SCED or that it has been instructed not to exceed its Base Point. |

3.9 Current Operating Plan (COP)

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

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

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| ***[NPRR1007: Replace paragraph (2) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (2) ERCOT shall use the information provided in the COP to calculate operating limits and Ancillary Service capabilities for each Resource for the Reliability Unit Commitment (RUC) processes. |

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

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

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

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

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

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

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

3.9.1 Current Operating Plan (COP) Criteria

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

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

(3) The Resource capacity in a QSE’s COP must be sufficient to supply the Ancillary Service Supply Responsibility of that QSE. Additionally, for a COP provided for an ESR, the QSE shall ensure that the Hour Beginning Planned State of Charge (HBSOC) for any two consecutive hours shall be feasible based on the ESR’s maximum rate of charge or discharge.

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| ***[NPRR1007, NPRR1014, NPRR1029, and NPRR1204: Replace applicable portions of paragraph (3) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007 and NPRR1204; or upon system implementation for NPRR1014 or NPRR1029:]***  (3) Each QSE that represents a Resource shall update its COP to reflect the ability of the Resource to provide each Ancillary Service by product and sub-type. Additionally, for a COP provided for an ESR, the QSE shall ensure that the Hour Beginning Planned State of Charge (HBSOC) for any two consecutive hours shall be feasible based on the ESR’s maximum rate of charge or discharge. |

(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;

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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| ***[NPRR1007, NPRR1014, and NPRR1029: Replace paragraph (N) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029:]***  (N) SHUTDOWN – The Resource is On-Line and in a shutdown sequence, and is not eligible for an Ancillary Service award. This Resource Status is only to be used for Real-Time telemetry purposes; |

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

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| ***[NPRR1007, NPRR1014, and NPRR1029: Replace paragraph (O) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029:]***  (O) STARTUP – The Resource is On-Line and in a start-up sequence and is not eligible for an Ancillary Service award, unless coming On-Line in response to a manual deployment of ERCOT Contingency Reserve Service (ECRS) or Non-Spinning Reserve (Non-Spin). This Resource Status is only to be used for Real-Time telemetry purposes; |

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

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| ***[NPRR1007, NPRR1014, and NPRR1029: Replace paragraph (P) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029:]***  (P) OFFQS – Off-Line but available for SCED deployment and to provide ECRS and Non-Spin, if qualified and capable. Only qualified Quick Start Generation Resources (QSGRs) may utilize this status; |

(Q) ONFFRRRS – Available for Dispatch of RRS when providing Fast Frequency Response (FFR) from Generation Resources. This Resource Status is only to be used for Real-Time telemetry purposes. A Resource with this Resource Status may also be providing Ancillary Services other than FFR; and

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

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| ***[NPRR1007, NPRR1014, and NPRR1029: Insert item (K) below upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029:]***  (K) ONSC – Resource is On-Line operating as a synchronous condenser and available to provide Responsive Reserve (RRS) and ECRS, if qualified and capable, and for commitment by RUC, but is unavailable for Dispatch by SCED. For SCED, Resource Base Points will be set equal to the telemetered net real power of the Resource available at the time of the SCED execution; and |

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

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| ***[NPRR1007, NPRR1014, NPRR1029, and NPRR1188: Replace item (R) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014, NPRR1029, or NPRR1188:]***  (R) ONHOLD – Resource is On-Line but temporarily unavailable for Dispatch by SCED or Ancillary Service awards due to a valid and verifiable operational reason. This Resource Status is only to be used for Real-Time telemetry purposes. For SCED, Resource Base Points will be set equal to the telemetered net real power of the Resource available at the time of the SCED execution. |

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

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

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

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

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

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| ***[NPRR1007, NPRR1014, and NPRR1029: Replace item (C) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029:]***  (B) OFF – Off-Line but available for commitment in the Day-Ahead Market (DAM), RUC, and providing Non-Spin, if qualified and capable; |

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

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

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

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

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| ***[NPRR1188: Replace item (A) above with the following upon system implementation:]***  (A) ONRGL – Available for Dispatch of Regulation Service by Load Frequency Control (LFC) and, for any remaining Dispatchable capacity, by SCED with an Energy Bid Curve; |

(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 (CLR) by SCED with an RTM Energy Bid;

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| ***[NPRR1188: Replace item (D) above with the following upon system implementation:]***  (D) ONCLR – Available for Dispatch as a Controllable Load Resource (CLR) by SCED with an Energy Bid Curve; |

(E) ONRL – Available for Dispatch of RRS or Non-Spin, excluding CLRs. A Load Resource, excluding CLR, may not provide ECRS with this Resource Status;

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

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| ***[NPRR1188: Insert items (F) and (G) below upon system implementation and renumber accordingly:]***  (F) ONTEST – On-Line blocked from SCED for operations testing;  (G) ONHOLD – CLR is On-Line but temporarily unavailable for Dispatch by SCED or providing Ancillary Service due to a valid and verifiable operational reason. This Resource Status is only to be used for Real-Time telemetry purposes. For SCED, Resource Base Points will be set equal to the telemetered net real power of the Resource available at the time of the SCED execution. |

(F) ONECL – Available for Dispatch of ECRS or available for Dispatch of ECRS and RRS simultaneously, excluding CLRs;

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

(G) OUTL – Not available;

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| ***[NPRR1188: Replace item (G) above with the following upon system implementation:]***  (I) OUTL – Not available. For a CLR that is not an Aggregate Load Resource (ALR), this status can only be used when the Resource is Off-Line and unavailable with its energy consumption at zero; |

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

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

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| ***[NPRR1007, NPRR1014, NPRR1029: Insert item (B) below upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029:]***  (B) ONL – On-Line and available for Dispatch by SCED or providing Ancillary Services. |

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| ***[NPRR1014 or NPRR1029: Insert applicable portions of paragraph (iv) below upon system implementation:]***  (iv) Select one of the following for Energy Storage Resources (ESRs). Unless otherwise provided below, these Resource Statuses are to be used for COP and Real-Time telemetry purposes:  (A) ON – On-Line Resource with Energy Bid/Offer Curve;  (B) ONOS – On-Line Resource with Output Schedule;  (C) ONTEST – On-Line blocked from SCED for operations testing (while ONTEST, an ESR may be shown on Outage in the Outage Scheduler);  (D) ONEMR – On-Line EMR (available for commitment or dispatch only for ERCOT-declared Emergency Conditions; the QSE may appropriately set LSL and High Sustained Limit (HSL) to reflect operating limits);  (E) ONHOLD – Resource is On-Line but temporarily unavailable for Dispatch by SCED or Ancillary Service awards. ESRs shall not be discharging into or charging from the grid. This Resource Status is only to be used for Real-Time telemetry purposes; and  (F) OUT – Off-Line and unavailable, or not connected to the ERCOT System and operating in a Private Microgrid Island (PMI); |

(c) The HSL;

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

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| ***[NPRR1014 and NPRR1029: Insert applicable portions of paragraph (ii) below upon system implementation:]***  (ii) For ESRs, the HSL may be negative; |

(d) The LSL;

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

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| ***[NPRR1014 and NPRR1029: Insert applicable portions of paragraph (ii) below upon system implementation:]***  (ii) For ESRs, the LSL may be positive; |

(e) The High Emergency Limit (HEL);

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

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

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| ***[NPRR1007, NPRR1014, and NPRR1029: Replace applicable portions of item (g) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029:]***  (g) Ancillary Service capability in MW for each product and sub-type. |

(i) Regulation Up Service (Reg-Up);

(ii) Regulation Down Service (Reg-Down);

(iii) RRS;

(iv) ECRS; and

(v) Non-Spin.

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

(h) For ESRs:

(i) Minimum State of Charge (MinSOC);

(ii) Maximum State of Charge (MaxSOC); and

(iii) HBSOC.

(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).

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| ***[NPRR1007, NPRR1014, and NPRR1029: Replace paragraph (c) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029:]***  (c) ERCOT systems shall allow only one Combined Cycle Generation Resource in a Combined Cycle Train to offer Off-Line Non-Spin in the DAM or SCED. |

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

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

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

(7) ERCOT may accept COPs only from QSEs.

(8) For the first 168 hours of the COP, ERCOT will update the HSL values for Wind-powered Generation Resources (WGRs) with the most recently updated Short-Term Wind Power Forecast (STWPF), and the HSL values for PhotoVoltaic Generation Resources (PVGRs) with the most recently updated Short-Term PhotoVoltaic Power Forecast (STPPF). ERCOT will notify the QSE via an Extensible Markup Language (XML) message each time COP HSL values are updated with the forecast values. A QSE representing a WGR may override the STWPF HSL value but must submit an HSL value that is less than or equal to the amount for that Resource from the most recent STWPF provided by ERCOT; a QSE representing a PVGR may override the STPPF HSL value but must submit an HSL value that is less than or equal to the amount for that Resource from the most recent STPPF provided by ERCOT.

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| ***[NPRR1029: Replace paragraph (8) above with the following upon system implementation:]***  (8) For the first 168 hours of the COP, ERCOT will update the HSL values for Wind-powered Generation Resources (WGRs) with the most recently updated Short-Term Wind Power Forecast (STWPF), and the HSL values for PhotoVoltaic Generation Resources (PVGRs) with the most recently updated Short-Term PhotoVoltaic Power Forecast (STPPF). A QSE representing a DC-Coupled Resource shall provide the capacity value of the Energy Storage System (ESS) that is included in the HSL of the DC-Coupled Resource, and ERCOT will update the DC-Coupled Resource’s HSL with the sum of the forecasts of the intermittent renewable generation component and the QSE-submitted value for the ESS component. ERCOT will notify the QSE via an Extensible Markup Language (XML) message each time COP HSL values are updated with the forecast values. A QSE representing a WGR may override the STWPF HSL value but must submit an HSL value that is less than or equal to the amount for that Resource from the most recent STWPF provided by ERCOT; a QSE representing a PVGR may override the STPPF HSL value but must submit an HSL value that is less than or equal to the amount for that Resource from the most recent STPPF provided by ERCOT. A QSE representing a DC-Coupled Resource may override the COP HSL value with a value that is lower than the ERCOT-populated value, and may override with a value that is higher than the ERCOT-populated value if the ESS component of the DC-Coupled Resource can support the higher value. |

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

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

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

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

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

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

(b) A hydro unit.

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

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

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

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| ***[NPRR1029: Insert paragraph (17) below upon system implementation and renumber accordingly:]***  (17) A QSE representing a DC-Coupled Resource shall not submit an HSL that exceeds the inverter rating or the sum of the nameplate ratings of the generation component(s) of the Resource. |

(17) A QSE representing an ESR shall ensure that COP values for a given hour follow the following rules:

(a) MinSOC is greater than or equal to the nameplate minimum MWh operating SOC limit;

(b) MaxSOC is less than or equal to the nameplate maximum MWh operating SOC limit; and

(c) HBSOC is a value between the corresponding COP values of MinSOC and MaxSOC.

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.

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

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

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

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| ***[NPRR1000: Replace paragraph (8) above with the following upon system implementation:]***  (8) A QSE representing a Resource that has an Energy Offer Curve valid for an hour of the COP may not designate a Resource Status of ONOS for that hour for that Resource. |

3.10 Network Operations Modeling and Telemetry

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

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| ***[NPRR857: Replace paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (1) ERCOT shall use the physical characteristics, ratings, and operational limits of all Transmission Elements of the ERCOT Transmission Grid and other information from Transmission Service Providers (TSPs), Direct Current Tie Operators (DCTOs), and Resource Entities to specify limits within which the transmission network is defined in the network models made available to Market Participants as noted below and used to operate the ERCOT Transmission Grid as updated. If a Private Use Network is not registered as a Resource Entity, then ERCOT shall use equivalent model data provided by TSPs, if available, that represents the Private Use Network in the TSPs’ modeling systems for use in the Network Operations Model. |

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

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| ***[NPRR857: Replace paragraph (2) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (2) Because the ERCOT market requires accurate modeling of Transmission Elements in order to send accurate Base Points and pricing signals to Market Participants, ERCOT shall manage the Network Operations Model. By providing Base Points and pricing signals by Electrical Bus to Market Participants, the Market Participants’ responses result in power flows on all Transmission Elements that ERCOT must monitor and, if necessary for reliability reasons, manage within ratings provided by each TSP, DCTO, and Resource Entity and limits assigned by ERCOT including Generic Transmission Limits (GTLs) as may be defined in Section 3.10.7.6, Use of Generic Transmission Constraints and Generic Transmission Limits. |

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

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| ***[NPRR857: Replace paragraph (3) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (3) Each TSP, DCTO, and Resource Entity shall provide ERCOT with equipment ratings and update the ratings as required by ERCOT. ERCOT may request that a TSP, DCTO, or Resource Entity provide detailed information on the methodology, including data for determination of each requested rating. ERCOT may review and comment on the methodology. ERCOT shall post all methodologies on the Market Information System (MIS) Secure Area within seven days following a change in methodology. |

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

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

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

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

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

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| ***[NPRR857: Replace paragraph (8) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (8) ERCOT shall track each data submittal received from TSPs and DCTOs via the NOMCR process and from Resource Entities via the Resource Registration process. Resource Registration data is converted by ERCOT to the appropriate NOMCR format through implementation and final testing of the change. ERCOT shall notify each TSP, DCTO, and Resource Entity when the requested change is processed and implemented in accordance with Section 3.10.1, Time Line for Network Operations Model Changes. ERCOT shall also provide the submitting TSP and DCTO a link to a Network Operations Model containing the change for verifying the implementation of the NOMCR and associated one-line displays. ERCOT shall post all NOMCRs on the MIS Certified Area for TSPs only within five Business Days following receipt of the NOMCR, consistent with the requirements regarding ERCOT Critical Energy Infrastructure Information (ECEII) set forth in Section 1.3, Confidentiality. When posting a NOMCR, each change must be posted using the CIM data exchange format showing incremental changes to the last Network Operations Model for TSPs only, to facilitate TSPs in updating their internal network models to reflect changes made at ERCOT. For each NOMCR, ERCOT shall post on the MIS Certified Area for TSPs only the current status on the in-service date for each NOMCR, including any prerequisite NOMCRs provided by the requestor. |

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

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

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| ***[NPRR857: Replace paragraph (10) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (10) Any requestor of any changes in system topology or telemetry must receive approval from ERCOT before connecting of any associated equipment to the ERCOT Transmission Grid. ERCOT shall notify a requestor of any deficiencies in its submittal for changes in system topology or telemetry. ERCOT shall accept corrections to the submittal if the requestor has corrected any deficiencies by the required submittal date specified in Section 3.10.1. ERCOT shall post any changes to a NOMCR on the MIS Certified Area for TSPs and DCTOs within three Business Days of accepting corrections. |

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

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| ***[NPRR857: Replace paragraph (11) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (11) On receipt of the information set forth in Section 3.10.7, ERCOT System Modeling Requirements, ERCOT shall review the information and notify the requestor of any required modifications. ERCOT may, at its discretion, require changes or more details regarding the work plan for any new or relocated facilities. The requestor shall notify ERCOT and any other affected Entities as soon as practicable of any ERCOT requested changes to the work plan. The requestor shall consult with other Entities likely to be affected and shall revise the work plan, following any necessary or appropriate discussions with ERCOT and other affected Entities. ERCOT shall approve or reject the request, including any revisions made by the requestor, within 15 days of receipt of the complete request and any revisions. Following ERCOT approval, ERCOT shall publish a summary of the revised NOMCR on the MIS Certified Area for TSPs and DCTOs. |

3.10.1 Time Line for Network Operations Model Changes

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

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| ***[NPRR857: Replace paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (1) ERCOT shall perform periodic updates to the Network Operations Model. Market Participants may provide Network Operations Model updates to ERCOT to implement planned transmission and Resource construction one year before the required submittal date below. TSPs, DCTOs, and Resource Entities must timely submit Network Operations Model changes pursuant to the schedule in this Section to be included in the updates. |

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

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| ***[NPRR995 and NPRR1246: Replace applicable portions of paragraph (2) above with the following upon system implementation for NPRR995; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1246:]***  (2) For a facility addition, revision, or deletion to be included in any Network Operations Model update, all technical modeling information must be submitted to ERCOT pursuant to the ERCOT NOMCR process or the applicable Resource Registration process for Resource Entities. If a Resource Entity is required to follow the generation interconnection process for a new Generation Resource, Energy Storage Resource (ESR), Settlement Only Generator (SOG), or Settlement Only Energy Storage System (SOESS) as described in Planning Guide Section 5, Generator Interconnection or Modification, it must meet the conditions of Planning Guide Section 6.9, Addition of Proposed Generation to the Planning Models, before submitting a change to the Network Operations Model to reflect the new Generation Resource, ESR, SOG, or SOESS. |

(3) TSPs and Resource Entities shall submit all Network Operations Model updates that are not subject to the requirements of paragraph (4) below by the applicable deadline to submit information to ERCOT for the target date of inclusion in the production model detailed in the table below. 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 (6) | Update Network Operations Model Production Environment | Target Physical Equipment included in Production Model  Note 4 |
| --- | --- | --- | --- | --- |
| Jan 1 | Feb 15 | March 15 | April 1 | Month of April |
| Feb 1 | March 15 | April 15 | May 1 | Month of May |
| March 1 | April 15 | May 15 | June 1 | Month of June |
| April 1 | May 15 | June 15 | July 1 | Month of July |
| May 1 | June 15 | July 15 | August 1 | Month of August |
| June 1 | July 15 | August 15 | September 1 | Month of September |
| July 1 | August 15 | September 15 | October 1 | Month of October |
| August 1 | September 15 | October 15 | November 1 | Month of November |
| September 1 | October 15 | November 15 | December 1 | Month of December |
| October 1 | November 15 | December 15 | January 1 | Month of January (the next year) |
| November 1 | December 15 | January 15 | February 1 | Month of February (the next year) |
| December 1 | January 15 | February 15 | March 1 | Month of March (the next year) |

Notes:

1. TSP and Resource Entity data submissions complete per the NOMCR process or other ERCOT-prescribed process applicable to Resource Entities for inclusion in next update period.

2. Network Operations Model data changes and preliminary fidelity test complete by using the Network Operations Model test facility described in paragraph (3) of Section 3.10.4, ERCOT Responsibilities. A test version of the Redacted Network Operations Model will be posted to the MIS Secure Area for Market Participants and Network Operations Model to the MIS Certified Area for TSPs as described in paragraph (9) of Section 3.10.4, for market review and further testing by Market Participants.

3. Testing of the Redacted Network Operations Model by Market Participants and Network Operations Model by TSPs is complete and ERCOT begins the Energy Management System (EMS) testing prior to placing the new model into the production environment.

4. Updates include changes starting at this date and ending within the same month. The schedule for Operations Model load dates will be published by ERCOT on the ERCOT website.

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| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| ***[NPRR857: Replace paragraph (3) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities for NPRR857:]***  (3) TSPs, DCTOs, and Resource Entities shall submit all Network Operations Model updates that are not subject to the requirements of paragraph (4) below by the applicable deadline to submit information to ERCOT for the target date of inclusion in the production model detailed in the table below. 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 (6)** | **Update Network Operations Model Production Environment** | **Target Physical Equipment included in Production Model**  **Note 4** | | --- | --- | --- | --- | --- | | January 1 | February 15 | March 15 | April 1 | Month of April | | February 1 | March 15 | April 15 | May 1 | Month of May | | March 1 | April 15 | May 15 | June 1 | Month of June | | April 1 | May 15 | June 15 | July 1 | Month of July | | May 1 | June 15 | July 15 | August 1 | Month of August | | June 1 | July 15 | August 15 | September 1 | Month of September | | July 1 | August 15 | September 15 | October 1 | Month of October | | August 1 | September 15 | October 15 | November 1 | Month of November | | September 1 | October 15 | November 15 | December 1 | Month of December | | October 1 | November 15 | December 15 | January 1 | Month of January (the next year) | | November 1 | December 15 | January 15 | February 1 | Month of February (the next year) | | December 1 | January 15 | February 15 | March 1 | Month of March (the next year) |   Notes:  1. TSP, DCTO, and Resource Entity data submissions complete per the NOMCR process or other ERCOT-prescribed process applicable to Resource Entities for inclusion in next update period.  2. Network Operations Model data changes and preliminary fidelity test complete by using the Network Operations Model test facility described in paragraph (3) of Section 3.10.4, ERCOT Responsibilities. A test version of the Redacted Network Operations Model will be posted to the MIS Secure Area for Market Participants and Network Operations Model to the MIS Certified Area for TSPs as described in paragraph (9) of Section 3.10.4, for market review and further testing by Market Participants.  3. Testing of the Redacted Network Operations Model by Market Participants and Network Operations Model by TSPs is complete and ERCOT begins the Energy Management System (EMS) testing prior to placing the new model into the production environment.  4. Updates include changes starting at this date and ending within the same month. The schedule for Operations Model load dates will be published by ERCOT on the ERCOT website. |

(4) Resource Entities shall submit complete initial Resource Registration data for inclusion in the ERCOT Network Operations Model as described in paragraph (6) of Planning Guide Section 6.8.1, Resource Registration, by the applicable deadline for the Resource Entity to submit complete information to ERCOT for the target date of inclusion in the production model detailed in the table below. ERCOT shall update the Network Operations Model according to the following table:

| Deadline for Resource Entity to Submit Complete Information to ERCOT  Note 1 | Deadline for Resource Registration Data to Meet Criteria for ERCOT Acceptance  Note 2 | Model Complete and Available for Test  Note 3 | Updated Network Operations Model Testing Complete  Note 4  Paragraph (6) | Update Network Operations Model Production Environment | Target Physical Equipment included in Production Model  Note 5 |
| --- | --- | --- | --- | --- | --- |
| December 1 | January 1 | February 15 | March 15 | April 1 | Month of April |
| January 1 | February 1 | March 15 | April 15 | May 1 | Month of May |
| February 1 | March 1 | April 15 | May 15 | June 1 | Month of June |
| March 1 | April 1 | May 15 | June 15 | July 1 | Month of July |
| April 1 | May 1 | June 15 | July 15 | August 1 | Month of August |
| May 1 | June 1 | July 15 | August 15 | September 1 | Month of September |
| June 1 | July 1 | August 15 | September 15 | October 1 | Month of October |
| July 1 | August 1 | September 15 | October 15 | November 1 | Month of November |
| August 1 | September 1 | October 15 | November 15 | December 1 | Month of December |
| September 1 | October 1 | November 15 | December 15 | January 1 | Month of January (the next year) |
| October 1 | November 1 | December 15 | January 15 | February 1 | Month of February (the next year) |
| November 1 | December 1 | January 15 | February 15 | March 1 | Month of March (the next year) |

Notes:

1. The date listed in this column shall serve as the deadline for initial submission of complete Resource Registration data to ERCOT, as described in paragraph (2) of Planning Guide Section 6.8.2, Resource Registration Process. ERCOT may work with the Resource Entity to resolve any data quality issues found in the Resource Registration data for up to one month after the submission date that corresponds to the date listed in this column. If ERCOT determines any Resource Registration data deficiencies are not sufficiently resolved by the end of the one-month period, then that submission shall be treated as a new initial submission for the following month.

2. Resource Entity data submission must be deemed complete by ERCOT with all data deficiencies resolved per the process described in Planning Guide Section 6.8.2 by this date.

3. 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. 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.

4. Testing of the Redacted Network Operations Model by Market Participants and Network Operations Model by TSPs is complete and ERCOT begins the EMS testing prior to placing the new model into the production environment.

5. Updates include changes starting at this date and ending within the same month. The schedule for Operations Model load dates will be published by ERCOT on the ERCOT website.

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

(6) 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:

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

3.10.2 Annual Planning Model

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

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

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

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

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| ***[NPRR1240: Replace paragraph (4) above with the following upon system implementation:]***  (4) ERCOT shall make available to TSPs and/or Distribution Service Providers (DSPs) the schedule for updating transmission information. |

(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;

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| ***[NPRR1246: Replace item (c) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (c) Generation Resource and ESR locations; |

(d) Transmission Elements;

(e) Transmission impedances;

(f) Transmission ratings, excluding Relay Loadability Ratings;

(g) Contingency lists;

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

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

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

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

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

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

3.10.4 ERCOT Responsibilities

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

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| ***[NPRR1240: Replace paragraph (1) above with the following upon system implementation:]***  (1) ERCOT shall design, install, operate, and maintain its systems and establish applicable related processes to meet the State Estimator Standards for Transmission Elements that under typical system conditions potentially affect the calculation of Locational Marginal Prices (LMPs) as described in Section 3.10.7.5, Telemetry Standards, and Section 3.10.9, State Estimator Standards. ERCOT shall post all documents relating to the State Estimator Standards on the MIS Secure Area, except where otherwise stated in Section 3.10.9.6, Telemetry and State Estimator Performance Monitoring. |

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

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

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

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

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| ***[NPRR857: Replace paragraph (5) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (5) When implementing Transmission Element changes, ERCOT shall correct errors uncovered during testing that are due to submission of inaccurate information. Each TSP, DCTO, and Resource Entity shall provide reasonably accurate information at the time of the original submission. |

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

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

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

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| ***[NPRR857: Replace paragraph (8) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (8) TSPs, DCTOs, and Resource Entities, with ERCOT’s assistance, shall validate their portion of the Network Operations Model according to the timeline provided in Section 3.10.1. ERCOT shall provide TSPs access, consistent with the requirements regarding ECEII set forth in Section 1.3, Confidentiality, to an environment of the ERCOT EMS where the Network Operations Model and the results of the Real-Time State Estimator are available for review and analysis within five minutes of the Real-Time solution. This environment is provided as a tool to TSPs to perform power flow studies, contingency analyses and validation of State Estimator results. |

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

3.10.5 TSP Responsibilities

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

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

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

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

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

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| ***[NPRR857: Replace Section 3.10.5 above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  ***3.10.5 TSP and DCTO Responsibilities***  (1) Each TSP and DCTO shall design, implement, operate, and maintain its systems to meet the requirements of Section 3.10.7.5, Telemetry Requirements, for measurements facilitating the observability of the Electrical Buses used for Security-Constrained Economic Dispatch (SCED). However, there is no obligation to re-construct or retrofit already existing installations except as shown to be needed in order to comply with Section 3.10.7.5 and Section 3.10.9, State Estimator Requirements.  (2) Each TSP and DCTO shall add telemetry to equipment it owns and directly operates and controls at ERCOT’s request to maintain observability and redundancy requirements as specified herein, and under Section 3.10.7.5. Nothing in this subsection prohibits a TSP from adding telemetry to equipment it does not own but directly operates and controls. ERCOT shall request such additions when a lack of data telemetry has caused, or can be demonstrated to result in, inaccuracies between Real-Time measurements and modeling outcomes that could result in incorrect LMP prices or potential reliability problems.  (3) Each TSP and DCTO shall provide to ERCOT planned construction information, including Certificate of Convenience and Necessity (CCN) application milestone dates if applicable, all of which shall be updated according to a schedule established by ERCOT.  (4) Each TSP shall provide to ERCOT project status updates of Transmission Facilities that are part of an Reliability Must-Run (RMR) or Must Run Alternative (MRA) exit strategy corresponding to a specific RMR or MRA Agreement that has not been terminated, which shall be updated by the first Business Day of each month, noting any acceleration or delay in planned completion date.  (5) A QSE must receive approval from a TSP prior to using the TSP’s telemetry as part of a Generation Resource’s Bulk Electric System protection scheme or for generation control. If a TSP has approved a QSE’s use of the TSP’s telemetry, the TSP shall inform the QSE of any telemetry changes with reasonable notice prior to the change or where prior notice is not possible as soon as reasonably practicable thereafter, including discontinuation of the TSP’s provision of such telemetry, and the timeline for the changes. |

3.10.6 QSE and Resource Entity Responsibilities

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

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| ***[NPRR995 and NPRR1246: Replace applicable portions of paragraph (1) above with the following upon system implementation for NPRR995; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1246:]***  (1) Resource Entities shall provide Resource Registration data pursuant to Planning Guide Section 6.8.2, Resource Registration Process, to ERCOT and to TSPs upon request. The Resource Registration data will contain information describing each Generation Resource, ESR, SOG, SOESS, and Load Resource that it represents under Section 3.10.7.2, Modeling of Resources and Transmission Loads. |

(2) QSEs shall ensure availability of telemetry to generation and transmission equipment its Resource Entity owns at ERCOT’s request to maintain observability and redundancy requirements as specified herein, and under Section 3.10.7.5, Telemetry Requirements. ERCOT shall request such additions when a lack of data telemetry has caused, or can be demonstrated to result in, inaccuracies between Real-Time measurements and modeling outcomes that could result in incorrect LMP prices or potential reliability problems.

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

(a) Cold weather temperature limits:

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

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

(iii) At least one of the following:

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

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

(iv) At least one of the following:

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

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

(b) Hot weather temperature limits:

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

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

(iii) At least one of the following:

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

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

(iv) At least one of the following:

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

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

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

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

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

3.10.7 ERCOT System Modeling Requirements

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

**3.10.7.1 Modeling of Transmission Elements and Parameters**

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

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| ***[NPRR857: Replace paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (1) ERCOT and each TSP, DCTO, and Resource Entity shall coordinate to define each Transmission Element such that the TSP’s control center operational model and ERCOT’s Network Operations Model are consistent. |

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

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| ***[NPRR857: Replace paragraph (2) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (2) Each Transmission Element must have a unique identifier using a consistent naming convention used between ERCOT, Resource Entities, TSPs, and DCTOs. ERCOT shall develop the naming convention with the assistance of the TSP and the approval of TAC. In addition to the Network Operations Model releases described in Section 3.10.1, Time Line for Network Operations Model Change Requests, ERCOT shall provide all names and parameters of all Transmission Elements to Market Participants posted on MIS Secure Area by 0600 each day. |

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

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| ***[NPRR857: Replace paragraph (3) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (3) If the responsible TSP or DCTO submits a NOMCR for non-operational changes, such as name changes for Transmission Elements, ERCOT shall implement the request. |

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

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| ***[NPRR857: Replace paragraph (4) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (4) Each Resource Entity shall provide the data requested in this Section through the Resource Registration data provided pursuant to relevant authorities, including Planning Guide Section 6.8.2, Resource Registration Process. |

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| ***[NPRR1133: Insert paragraph (5) below upon system implementation of NPRR857:]***  (5) Each DC Tie Facility owner shall provide the model data needed to accurately reflect the physical characteristics of the DC Tie Facility in ERCOT’s Network Operations Model to its DCTO, and the DCTO shall submit the data to ERCOT. The DC Tie Facility owner is responsible for the accuracy and completeness of the data submitted to ERCOT through its DCTO. |

3.10.7.1.1 Transmission Lines

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

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

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| ***[NPRR857: Replace paragraph (2) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (2) For each of its transmission lines operated as part of the ERCOT Transmission Grid, each TSP, DCTO, and if applicable, Resource Entity, shall provide ERCOT with the following information consistent with the ratings methodology prescribed in the ERCOT Operating Guides: |

(a) Equipment owner(s);

(b) Equipment operator(s);

(c) Transmission Element name;

(d) Line impedance;

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

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

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

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| ***[NPRR857: Replace paragraph (3) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (3) The TSP, DCTO, and Resource Entity may submit special transfer limits and stability limits for secure and reliable grid operations for ERCOT approval. ERCOT has sole decision-making authority and responsibility to determine the limits to be applied in grid operations. |

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

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| ***[NPRR857: Replace paragraph (4) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (4) The TSP, DCTO, and Resource Entity may implement protective relay and control systems and set values appropriate to de-energize faulted equipment and meet the TSP, DCTO, and Resource Entity obligations for public or employee safety, and when necessary to prevent in-service or premature equipment failure consistent with Good Utility Practice and accepted industry standards. The TSP, DCTO, and Resource Entity shall include those limits as Relay Loadability Ratings when providing ERCOT with ratings or proposed transfer limits. |

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

3.10.7.1.2 Transmission Buses

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

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

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| ***[NPRR857: Replace paragraph (2) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (2) Each TSP, DCTO, and if applicable, Resource Entity, shall provide ERCOT with the following information, subject to the naming conventions in Section 3.10.7.1, Modeling of Transmission Elements and Parameters: |

(a) Equipment owner(s);

(b) Equipment operator(s);

(c) The Transmission Element name;

(d) The substation name;

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

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

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

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| ***[NPRR857: Replace paragraph (3) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (3) To accommodate the Outage Scheduler, the TSP, DCTO, and Resource Entity may define a separate name and Transmission Element for any Electrical Bus that can be physically separated by a manual switch or breaker within a substation. |

3.10.7.1.3 Transmission Breakers and Switches

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

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

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| ***[NPRR857: Replace paragraph (2) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (2) Each TSP, DCTO, and Resource Entity shall provide ERCOT with the following information, subject to the naming conventions in Section 3.10.7.1, Modeling of Transmission Elements and Parameters: |

(a) Equipment owner(s);

(b) Equipment operator(s);

(c) The Transmission Element name;

(d) The substation name;

(e) Connectivity;

(f) Normal status;

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

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| ***[NPRR857: Replace item (g) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities for NPRR857:]***  (g) Synchronism Check Relay phase angle limits that are applied to operator-initiated, non-automated control actions of TSP-owned or DCTO-owned transmission breakers; and |

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

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

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| ***[NPRR857: Replace paragraph (3) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (3) ERCOT shall develop methods to accurately model changes in transmission line loading resulting from Load rollover schemes transferring more than ten MW. This may include modeling distribution circuit breakers, dead line sensing, or other methods that signal when the Load should be transferred from one transmission line to another transmission line. ERCOT may employ heuristic rule sets for all manual Load transfers and for automated transfers where feasible. ERCOT application software is required to model the effects of automatic or manual schemes in the field transfer Load under line outage conditions. Each TSP and as applicable, each DCTO and Resource Entity, shall define the Load rollover schemes under Section 3.10.7.2, Modeling of Resources and Transmission Loads, and furnish this information to ERCOT. Transmission field (right-of-way) switches must be connected to a named Electrical Bus and be included in the Network Operations Model. |

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

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| ***[NPRR1246: Replace Section 3.10.7.1.4 above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  3.10.7.1.4 Transmission, Main Power Transformers (MPTs) and Generation Step-Up Transformers |

(1) ERCOT shall model all transformers with a nominal low side (i.e., secondary, nottertiary) voltage above 60 kV.

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

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| ***[NPRR1246: Replace paragraph (2) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (2) For Generation Resources and ESRs, ERCOT shall model all Main Power Transformers (MPTs) and Generator Step-Up (GSU) transformers greater than ten MVA to provide for accurate representation of generator voltage control capability including the capability to accept a system operator entry of a specific no-load tap position, or if changeable under Load, accept telemetry of the current tap position. |

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

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| ***[NPRR857: Replace paragraph (3) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (3) Each TSP, DCTO, and Resource Entity shall provide ERCOT with information to accurately describe each transformer in the Network Operations Model including any tertiary Load as required by ERCOT. Each TSP, DCTO, and Resource Entity shall provide ERCOT with the following information, subject to the naming conventions in Section 3.10.7.1, Modeling of Transmission Elements and Parameters: |

(a) Equipment owner(s);

(b) Equipment operator(s);

(c) The Transmission Element name;

(d) The substation name;

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

(f) Connectivity;

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

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

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

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

3.10.7.1.5 Reactors, Capacitors, and other Reactive Controlled Sources

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

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

(a) Equipment owner(s);

(b) Equipment operator(s);

(c) The Transmission Element name;

(d) The substation name;

(e) Voltage or time switched on;

(f) Voltage or time switched off;

(g) Associated switching device name;

(h) Connectivity;

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

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

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

**3.10.7.2 Modeling of Resources and Transmission Loads**

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

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| ***[NPRR995 and NPRR1246: Replace applicable portions of paragraph (1) above with the following upon system implementation for NPRR995; upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1246:]***  (1) Each Resource Entity shall provide ERCOT and its interconnecting TSP with information describing each of its Generation Resources, ESRs, SOGs, SOESSs, and Load Resources connected to the ERCOT System. All Transmission Generation Resources (TGRs), Transmission ESRs (TESRs), Settlement Only Transmission Generators (SOTGs), Settlement Only Transmission Self-Generators (SOTSGs), Settlement Only Transmission Energy Storage Systems (SOTESSs), and the non-TSP MPTs greater than ten MVA, must be modeled to provide equivalent generation injections to the ERCOT Transmission Grid. ERCOT shall coordinate the modeling of Generation Resources, ESRs, Private Use Networks, and Load Resources with their owners to ensure consistency between TSP models and ERCOT models. |

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

(3) Each Resource Entity representing a Distribution Generation Resource (DGR) or Distribution Energy Storage Resource (DESR) that is registered with ERCOT pursuant to Section 16.5, Registration of a Resource Entity, shall provide ERCOT, its interconnecting DSP, and the TSP that interconnects the DSP to the transmission system with information describing each of its DGR or DESR facilities, and additional information and telemetry as required by ERCOT and the interconnecting DSP. ERCOT shall coordinate with representatives of the Resource Entity to represent the registered DGR or DESR facilities at their appropriate Electrical Bus in the Network Operations Model.

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

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| ***[NPRR995: Replace paragraph (4) above with the following upon system implementation:]***  (4) Each Resource Entity representing a Settlement Only Distribution Generator (SODG) or Settlement Only Distribution Energy Storage System (SODESS) facility that is registered with ERCOT pursuant to paragraph (5) of Section 16.5 shall provide ERCOT, its interconnecting DSP, and the TSP that interconnects the DSP to the transmission system with information describing each of its SODG or SODESS facilities, and additional information and telemetry as required by ERCOT. ERCOT shall coordinate with representatives of the Resource Entity to map registered SODG or SODESS facilities to their appropriate Load in the Network Operations Model. |

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

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

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

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| ***[NPRR857 and NPRR1234: Replace applicable portions of paragraph (7) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities for NPRR857; or upon system implementation for NPRR1234:]***  (7) Each TSP and DCTO shall provide ERCOT with information describing all transmission Load connections on the ERCOT Transmission Grid. Individual Load connections may be combined, at the discretion of ERCOT, with other Load connections on the same transmission line to represent a Load Point to facilitate state estimation of Loads that do not telemeter Load measurements. ERCOT shall define “Load Points”, which may be one or more combined Loads, for use in its Network Operations Model. A Load Point cannot be used to represent Load connections that are in different Load Zones. |

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

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| ***[NPRR857: Replace paragraph (8) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (8) ERCOT may require TSPs and DCTOs to provide additional Load telemetry to provide adequate modeling of the transmission system in accordance with Section 3.10.7.5, Telemetry Standards. When the TSP or DCTO does not own the station for which additional Load telemetry is being requested, the TSP shall request that the owner make the telemetry available. The TSP or DCTO shall notify ERCOT if the owner does not comply with the request. |

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

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

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

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| ***[NPRR1246: Replace paragraph (11) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (11) Loads associated with a Generation Resource or ESR in a common switchyard as defined in Section 10.3.2.3, Generation Netting for ERCOT-Polled Settlement Meters, and served through a transformer owned by the Resource Entity is treated as an auxiliary Load and must be netted first against any generation meeting the requirements under Section 10.3.2.3. |

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

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

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

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

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

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

(e) Either:

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

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

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

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

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

(14) For each Load Point within the ERCOT Network Operations Model, each TSP shall identify and provide an end-use industry classification when a Load Point represents a single end-use Customer or Service Delivery Point that has a historical or requested peak Demand of 25 MW or greater, either:

(a) By itself;

(b) In combination with other Load Points in the same substation that serve the same Customer or Service Delivery Point;

(c) Where, in addition to a Customer or Service Delivery Point with a 25 MW or larger peak Demand, other Customers with historical or requested Demands smaller than 25 MW that are not required to be modeled also take service at the same Load Point; or

(d) Where the single Customer or Service Delivery Point is served by multiple substations.

(15) The applicable TSP shall identify Load Points subject to the requirements of paragraph (14) above in the Network Operations Model according to the following schedule:

(a) Load Points associated with an interconnecting Customer with a requested peak Demand of 25 MW or greater shall be modeled prior to energization;

(b) Load Points associated with a Customer or Service Delivery Point with a historical peak Demand of 25 MW or greater achieved prior to January 1, 2025 shall be modeled via a spreadsheet NOMCR on or before September 1, 2025;

(i) For Customers or Service Delivery Points served by a DSP via a wholesale point of delivery provided by a TSP, the DSP shall provide a list of Customers, including end-use industry classification, to the interconnecting TSP on or before August 1, 2025; and

(c) If not already modeled pursuant to paragraph (b) above, Load Points associated with a Customer or Service Delivery Point that achieves a peak Demand of 25 MW or greater on or after January 1, 2025 shall be modeled on or before April 1 of the next calendar year after the peak Demand reached 25 MW via a spreadsheet NOMCR;

(i) For Customers or Service Delivery Points served by a DSP via a wholesale point of delivery provided by a TSP, the DSP shall provide a list of Customers, including end-use industry classification, to the interconnecting TSP on or before March 1.

(16) Each Resource Entity or Interconnecting Entity (IE) associated with an existing or proposed Generation Resource or ESR co-located with a Load as described in Section 10.3.2.3 shall represent the co-located Load using one or more Load Points that are separate from auxiliary Loads for the generator. If the aggregate co-located Load has a historical or requested peak Demand of 25 MW or greater, the Resource Entity or IE shall provide the end-use industry classification best representing the facility for each Load Point that is not an auxiliary Load. Calculation of peak Demand shall exclude the auxiliary Loads associated with Generation Resources or ESRs.

(17) A Resource Entity or IE with co-located Load that has a historical or requested peak Demand of 25 MW or greater provide end-use industry classification according to the following schedule:

(a) The classification of a new co-located Load associated with a new generation interconnection request or with an operational Generation Resource or ESR shall be provided in the Resource Registration data and included in the Network Operations Model prior to energization of the co-located Load;

(b) The classification of an operational co-located Load with a historical peak Demand of 25 MW or greater achieved prior to January 1, 2025 shall be provided via an update to the Resource Registration data on or before September 1, 2025;

(c) The classification of an operational co-located Load that achieves a peak Demand of 25 MW or greater on or after January 1, 2025 shall be provided via an update to the Resource Registration data within three months from the date peak Demand reaches 25 MW;

(18) ERCOT shall treat Load Point identification and end-use classification provided pursuant to paragraphs (14) through (17) of this Section as “Proprietary Customer Information,” as defined in paragraph (1)(r) of Section 1.3.1.1, Items Considered Protected Information.

(19) Each Large Load connected at transmission voltage shall be represented by a single Load Point or multiple Load Points at a single substation in the ERCOT Network Operations Model. No other Loads shall be included in these Load Points.

***3.10.7.2.1 Reporting of Demand Response***

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

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| ***[NPRR1007: Replace paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (1) ERCOT shall post on the ERCOT website by the fifth Business Day after the start of a calendar month a report of the MW of Demand response that is participating in the past month in Emergency Response Service (ERS), Ancillary Service as a Load Resource, or any pilot project permitted by subsection (k) of P.U.C. Subst. R. 25.361, Electric Reliability Council of Texas (ERCOT). The data shall be aggregated according to the corresponding 2003 ERCOT Congestion Management Zone (CMZ). Data for participation in ERS shall be based on contracted amounts for each type of service for that calendar month. ERCOT shall set out separately MW contracted from both ERS Generators and generators that are participating by offsetting ERS Loads (with aggregated and non-aggregated ERS Generators set forth separately) and MW of ERS Loads. To the extent that a participating generator is not registered with ERCOT, information about the nameplate rating of the generator and the maximum deliverable to the ERCOT Transmission Grid or to serve native load shall be collected through the ERS contracting process. The report shall include these values for each ERS Contract Period broken down by ERS Time Period. Data for Ancillary Services shall be based on the Ancillary Service Resource awards in the RTM. ERCOT’s posting of Ancillary Service and pilot project participation data shall include the average MW capacity by service type by hour (or by another time period, if a pilot project service is not procured hourly). |

***3.10.7.2.2 Annual Demand Response Report***

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

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

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

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

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

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

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

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

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

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

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

(a) An acknowledgement of the participation requirement;

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

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

(d) Specifically for REPs, an indication as to which of the methods described in the Other Binding Document titled “Demand Response Data Definitions and Technical Specifications” the REP intends to use to submit files to and receive files from ERCOT; and

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

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

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

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

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

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

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

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

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

**3.10.7.3 Modeling of Private Use Networks**

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

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

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

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

(iii) Contains generation registered to provide Ancillary Services.

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

(i) Equipment owner(s);

(ii) Equipment operator(s);

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

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

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

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

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

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

(ix) Other interconnection data as required by ERCOT.

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

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

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

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

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

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

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

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| ***[NPRR857: Replace paragraph (2) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (2) Proposed new RASs, AMPs and RAPs and proposed changes to RASs, AMPs and RAPs must be submitted to ERCOT for review and approval. ERCOT shall seek input from TSPs, DCTOs, and Resource Entities that own Transmission Facilities included in the RASs or AMPs or RAPs, and shall approve proposed new RASs, AMPs and RAPs and proposed changes to RASs, AMPs and RAPs in accordance with the process outlined in the Operating Guides. This shall include verification of the Network Operations Model. ERCOT shall provide notification to the market and post all RASs, AMPs and RAPs under consideration on the MIS Secure Area within five Business Days of receipt. |

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

**3.10.7.5 Telemetry Requirements**

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

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

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| ***[NPRR857: Replace paragraph (2) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (2) The telemetry provided to ERCOT by each TSP, QSE, or DCTO must be updated at a ten second or less scan rate and be provided to ERCOT at the same rate. Each TSP, DCTO, and QSE shall install appropriate condition detection capability to notify ERCOT of potentially incorrect data from loss of communication or scan function. Condition codes must accompany the data to indicate its quality and whether the data has been measured within the scan rate requirement. Also, ERCOT shall analyze data received for possible loss of updates. Similarly, ERCOT shall provide condition detection capability on loss of telemetry links with the TSP, DCTO, and QSE. ERCOT shall represent data condition codes from each TSP, DCTO, and QSE in a consistent manner for all applicable ERCOT applications. |

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

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

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

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| ***[NPRR857: Replace paragraph (3) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (3) Each TSP, DCTO, and QSE shall use fully redundant ICCP links between its control center systems and ERCOT systems such that any single element of the communication system can fail and:  (a) For server failures, complete information must be re-established within five minutes by automatic failover to alternate server(s); and  (b) For all other failures, complete information must continue to flow between the TSP’s, DCTO’s, QSE’s, and ERCOT’s control centers with updates of all data continuing at a 30 second or less scan rate. |

(4) When ERCOT identifies a reliability concern, a deficiency in system observability, or a deficiency in measurement to support the representation of Model Loads, and that concern or deficiency is not due to any inadequacy of the State Estimator program, additional telemetry may be requested as described in Section 3.10.7.5.9, ERCOT Requests for Telemetry.

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| ***[NPRR1234: Replace paragraph (4) above with the following upon system implementation:]***  (4) When ERCOT identifies a reliability concern, a deficiency in system observability, or a deficiency in measurement to support the representation of Load Points, and that concern or deficiency is not due to any inadequacy of the State Estimator program, additional telemetry may be requested as described in Section 3.10.7.5.9, ERCOT Requests for Telemetry. |

3.10.7.5.1 Continuous Telemetry of the Status of Breakers and Switches

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

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

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

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

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

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

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| ***[NPRR857 and NPRR1234: Replace applicable portions of paragraphs (1) through (4) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities for NPRR857; and upon system implementation for NPRR1234:]***  (1) Each TSP, DCTO, and QSE shall provide telemetry, as described in this subsection, to ERCOT on the status of all breakers and switches it owns or its Resource Entity owns, respectively used to switch any Transmission Element or Load modeled by ERCOT.  (2) Each TSP, DCTO, and QSE is not required to install telemetry on individual breakers and switches it owns or its Resource Entity owns, respectively, where the telemetered status shown to ERCOT is current and free from ambiguous changes in state caused by the TSP, DCTO, or QSE switching operations and TSP, DCTO, or QSE personnel.  (3) Each TSP, DCTO, and QSE shall update the status of any breaker or switch it owns or its Resource Entity owns, respectively, through manual entries, if necessary, to communicate the actual current state of the device to ERCOT, except if the change in state is expected to return to the prior state within one minute.  (4) If in the sole opinion of ERCOT, the manual updates of the TSP, DCTO, or QSE have been unsuccessful in maintaining the accuracy required to support State Estimator performance to a TAC-approved predefined standard as described in Section 3.10.9, State Estimator Requirements, ERCOT may request that the TSP, DCTO, or QSE install complete telemetry from the breaker or switch it owns or its Resource Entity owns, respectively, to the TSP, DCTO, or QSE, and then to ERCOT.  (a) In making the determination to request installation of additional telemetry from a breaker or switch, ERCOT shall consider the economic implications of inaccurate representation of Load Points in LMP results versus the cost to remedy.  (b) If the TSP or associated QSE disputes the request for additional telemetry it owns or its Resource Entity owns, respectively, it may appeal the request pursuant to Section 3.10.7.5.9, ERCOT Requests for Telemetry. |

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

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| ***[NPRR857: Replace paragraph (5) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (5) ERCOT shall measure TSP, DCTO, and QSE performance in providing accurate data that do not include ambiguous changes in state and shall report the performance metrics on the MIS Secure Area on a monthly basis. |

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

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| ***[NPRR857: Replace paragraph (6) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (6) Unless there is an Emergency Condition, TSPs, DCTOs, and QSEs must obtain approval from ERCOT to purposely open a breaker or switch unless that breaker or switch is shown in a Planned Outage in the Outage Scheduler, or the device will return to its previous state within 60 minutes, or the device is a generator output circuit breaker. Also, TSPs, DCTOs, and QSEs must obtain approval from ERCOT before closing any breaker or switch, except in response to a Forced Outage, or an emergency, or the device will return to its previous state within 60 minutes, or the device is a generator output circuit breaker. |

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

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| ***[NPRR857: Replace paragraph (7) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (7) ERCOT shall monitor the data condition codes of all breakers and switches showing loss of communication or scan function in the Network Operations Model. When the telemetry of breakers and switches is lost, ERCOT shall use the last known state of the device for security analysis as updated by the Outage Scheduler and through verbal communication with the TSP, DCTO, or QSE. ERCOT’s systems must identify probable errors in switch or breaker status and ERCOT shall act to resolve or correct such errors in a timely manner as described in Section 6, Adjustment Period and Real-Time Operations. |

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

(9) Each QSE that represents a Split Generation Resource, with metering according to Section 3.8, Special Considerations, shall provide ERCOT with telemetry of the actual generator breakers and switches continuously providing ERCOT with the status of the individual Split Generation Resource.

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

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

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| ***[NPRR857: Replace paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (1) Each TSP, DCTO, and QSE shall provide telemetry of voltages, flows, and Loads on any modeled Transmission Element it owns or its Resource Entity owns, respectively, to the extent such may be required to estimate all transmission Load withdrawals and generation injections to and from the ERCOT Transmission Grid using the State Estimator and as needed to meet the State Estimator requirements set forth in Section 3.10.9, State Estimator Requirements, with consideration given to the economic implications of inaccurate LMP results versus the cost to remedy. |

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

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

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| ***[NPRR857: Replace paragraph (3) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (3) Each TSP, DCTO, and QSE shall provide telemetered measurements at a periodicity of ten seconds on modeled Transmission Elements it owns or its Resource Entity owns, respectively, to ensure State Estimator observability of any monitored voltage and power flow between their associated transmission breakers to the extent such can be shown to be needed to meet the State Estimator requirements set forth in Section 3.10.9. On monitored non-Load substations, ERCOT may request additional telemetry in accordance with Section 3.10.7.5.10, ERCOT Requests for Redundant Telemetry. |

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

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

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

(b) Five MW, whichever is greater.

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

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| ***[NPRR857: Replace paragraph (5) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (5) Each TSP, DCTO, QSE, and ERCOT shall develop a continuously operated program to maintain telemetry of all Transmission Element measurements to provide accurate State Estimator results as outlined in Section 3.10.9. For any location where there is a connection of multiple, measured, Transmission Elements, ERCOT shall have an automated process to detect and notify ERCOT System operators if the residual sum of all telemetered measurements is more than:  (a) 5% of the largest line Normal Rating at the State Estimator Bus; or  (b) Five MW, whichever is greater.  If a location chronically fails this test, ERCOT shall notify the applicable TSP, DCTO, or QSE and suggest actions that the TSP, DCTO, or QSE could take to correct the failure. Within 30 days, the TSP, DCTO, or QSE shall take the actions necessary to correct the failure or provide ERCOT with a detailed plan with a projected time frame to correct the failure. ERCOT shall post a notice on the MIS Secure Area of any State Estimator Buses not meeting the State Estimator requirements set forth in Section 3.10.9, including a list of all measurements and the residual errors on a monthly basis. |

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

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

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

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| ***[NPRR1098: Insert paragraph (9) below upon system implementation and satisfying the following conditions: (1) Southern Cross Transmission LLC (Southern Cross) provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a Transmission Service Provider (TSP) and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (9) Each TO designated by a DCTO operating a DC Tie meeting the applicability requirements of paragraph (1) of Section 3.15.4, Direct Current Tie Owner and Direct Current Tie Operator (DCTO) Responsibilities Related to Voltage Support, shall designate which telemetered measurement of the POIB voltage shall be utilized to determine compliance with target voltage instructions, and then update the designation as necessary in the Network Operations Model by submitting a NOMCR. Each TO shall telemeter this POI kV bus measurement to ERCOT via ICCP and the DCTO via telemetry. If the TO cannot provide a kV bus measurement at the POI, the TO may propose an alternate location subject to ERCOT approval. |

3.10.7.5.3 Required Telemetry of Voltage and Power Flow

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

(a) Real-Time generation data from QSEs;

(b) Planned and Forced Outage information from QSEs;

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

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

(ii) Line flow MW and MVAr;

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

(iv) Transmission Facility voltages; and

(v) Transformer MW, MVAr and tap;

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

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

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

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

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

(i) Dynamic schedules from QSEs.

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

3.10.7.5.4 General Telemetry Performance Criteria

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

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

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

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

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

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

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

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

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

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

3.10.7.5.5 Supplemental Telemetry Performance Criteria

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

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

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

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

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

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

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

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

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

3.10.7.5.6 TSP/QSE Telemetry Restoration

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

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

(a) Calibrate or repair the failing equipment;

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

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

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

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

3.10.7.5.7 Calibration, Quality Checking, and Testing

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

3.10.7.5.8 Inter-Control Center Communications Protocol (ICCP) Links

3.10.7.5.8.1 Data Quality Codes

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

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

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

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

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

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

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

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

3.10.7.5.8.2 Reliability of ICCP Associations

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

3.10.7.5.9 ERCOT Requests for Telemetry

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

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

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

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

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

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

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

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

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

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

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| ***[NPRR979: Replace paragraph (4) above with the following upon system implementation of NPRR857:]***  (4) No later than 60 days after receipt of a request for additional telemetry, the TSP, DCTO, or QSE shall:  (a) Accept ERCOT’s request for additional telemetry and notify ERCOT of the implementation schedule, which shall be no later than 18 months following the receipt of the request for additional telemetry;  (b) Provide an alternative proposal to ERCOT, for implementation no later than 18 months following the receipt of the request for additional telemetry, that meets the requirements described by ERCOT;  (c) Propose a normal topology change by changing normal status of switch(es) in the area that would eliminate the security violations that are ERCOT’s concern;  (d) Indicate that the requested telemetry point is at a location where the TSP, DCTO, or QSE does not have the authority to install the requested telemetry. For points on privately owned facilities connected to the ERCOT Transmission Grid, an attempt will be made to facilitate ERCOT's telemetry request;  (e) Provide ERCOT an analysis of the cost to comply with the request, so that, ERCOT can perform a cost justification with respect to the LMP market; or  (f) If the TSP, DCTO, or QSE disagrees with the request, the TSP, DCTO, or QSE may request that ERCOT withdraw its request for additional telemetry. |

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

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| ***[NPRR979: Replace paragraph (5) above with the following upon system implementation of NPRR857:]***  (5) If ERCOT rejects an alternative proposal pursuant to paragraph (4)(b), (c), or (f) above, the TSP, DCTO, or QSE may appeal the original request to TAC within 30 days of receiving notice of ERCOT’s rejection. If, after receiving an appeal, TAC does not resolve the appeal within 65 days, the TSP, DCTO, or QSE may present its appeal to the ERCOT Board. Notwithstanding the foregoing, a TSP, DCTO, or QSE is not required to provide telemetry measurements from a location not owned by that TSP, DCTO, or QSE if the location owner does not grant access to the TSP, DCTO, or QSE for the purpose of obtaining such measurements. ERCOT shall report such cases to the IMM. |

3.10.7.5.10 ERCOT Requests for Redundant Telemetry

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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| ***[NPRR1246: Replace paragraph (2) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (2) During the ERCOT quarterly stability assessment, performed pursuant to Planning Guide Section 5.3.5, ERCOT Quarterly Stability Assessment, if ERCOT determines a GTC is necessary for a new Generation Resource, ESR, or SOTSG due to localized stability issues associated with the output of the interconnecting Generation Resource, ESR, or SOTSG, the GTL for the GTC shall be set to the lowest non-zero limit for all system conditions outside those in which the limit is zero. |

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

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

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

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

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

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

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

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

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

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

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

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

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| ***[NPRR825 and NPRR1246: Replace applicable portions of Section 3.10.7.7 above with the following upon system implementation for NPRR825; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1246:]***  **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 or ESR 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 or ESR is needed, as well as other system conditions. |

3.10.8 Dynamic Ratings

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

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

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

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

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

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

**3.10.8.1 Dynamic Ratings Delivered via ICCP**

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

(a) Normal Rating; and

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

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

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

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

(a) Line ID;

(b) From station;

(c) To station;

(d) Weather Zone(s);

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

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

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

**3.10.8.3 Dynamic Rating Network Operations Model Change Requests**

(1) ERCOT shall use the NOMCR process by which TSPs provide electronically to ERCOT the dynamic rating table described in Section 3.10.8.2, Dynamic Ratings Delivered via Static Table and Telemetered Temperature.

**3.10.8.4 ERCOT Responsibilities Related to Dynamic Ratings**

(1) ERCOT shall provide a system to accept and implement Dynamic Ratings or temperatures to be applied to rating tables for each hour in the Day-Ahead and in the Operating Hour. ERCOT shall also:

(a) Provide software and processes that allow secure access for TSPs and Market Participants and that maintains a log of data provided and the actions of the TSP and ERCOT, to implement the Dynamic Ratings as described above;

(b) Use Dynamic Ratings for alarming, compliance with ERCOT and NERC requirements, and SCED purposes in both Real-Time operations and operational planning;

(c) Approve or reject the new Dynamic Rating request within 24 hours of receipt;

(d) Post Dynamic Ratings approved by ERCOT for each planned production load of the Network Operations Model on the MIS Secure Area. The posting will include the Transmission Element name, approved thermal rating limits, and the planned effective date; and

(e) Implement the approved Dynamic Rating automatically within 24 hours of approval.

(2) ERCOT shall provide a system to implement Dynamic Ratings and to obtain monthly expected ambient air temperatures to be applied to rating tables for the CRR Network Models. Temperatures applied to the rating tables shall be determined using the same method as described in item (3)(f) of Section 7.5.5.4, Simultaneous Feasibility Test. Transmission Elements that have Dynamic Ratings implemented in the Network Operations Model must have Dynamic Ratings in the CRR Network Models.

(3) ERCOT shall identify additional Transmission Elements that have a high probability of providing significant added economic efficiency to the ERCOT market through Dynamic Rating and request such Dynamic Ratings from the associated TSP. ERCOT shall post annually the list of the Transmission Elements and identify if the TSP has agreed to provide the rating on the MIS Secure Area.

**3.10.8.5 Transmission Service Provider Responsibilities Related to Dynamic Ratings**

(1) Each TSP shall:

(a) Provide ERCOT with tables of ratings for different ambient temperatures for Transmission Elements, as requested by ERCOT.

(b) Submit within two months a temperature adjusted rating table when a request is received from ERCOT unless multiple requests are made by ERCOT within the two-month period or unusual circumstances prevent the request from being accommodated in a timely fashion. Such circumstances must be explained to ERCOT in writing and must be posted by ERCOT on the MIS Secure Area within five Business Days of receipt.

(c) Provide Real-Time temperatures for each Weather Zone in which the TSP has existing dynamically rated transmission equipment, or alternatively provide rating updates for each temperature-adjusted line rating updated at least once every ten minutes.

3.10.9 State Estimator Requirements

(1) The appropriate TAC subcommittee shall coordinate with Market Participants to ensure a common understanding of the level of State Estimator performance required to enable LMP calculation and address the State Estimator’s ability to detect, correct, or otherwise accommodate communications system failures, failed data points, stale data condition codes, and missing or inaccurate measurements to the extent these capabilities contribute to LMP accuracy and State Estimator performance or as needed to meet reliability requirements.

**3.10.9.1 Considerations for State Estimator Requirements**

(1) In maintaining the State Estimator requirements, the following may be considered:

(a) Desired confidence levels of State Estimator results;

(b) Measurement requirements to estimate power injections and withdrawals at transmission voltage Electrical Buses defined in the SCED transmission model, which may provide for variations in criteria based on:

(i) The number of Transmission Elements connected to a given transmission voltage Electrical Bus;

(ii) The peak demand of the Load connected to a transmission voltage Electrical Bus;

(iii) The total of Resource capacity connected to a transmission voltage Electrical Bus;

(iv) The nominal transmission voltage level of an Electrical Bus;

(v) The number of Electrical Buses with injections or withdrawals along a circuit between currently monitored transmission voltage Electrical Bus;

(vi) Connection of Loads along a continuous, non-branching circuit that may be combined for modeling purposes;

(vii) The quantity of Load at an Electrical Bus that may have its connection to the transmission system automatically transferred to an Electrical Bus other than the one to which it is normally connected (rollover operation);

(vii) Electrical proximity to more than one Resource Node;

(viii) Degree or quality of continued observability following the loss of telemetry measurements resulting from a common mode failure of telemetry-related equipment (*i.e.*, an N-1 telemetry condition); and

(ix) Other parameters or circumstances, as appropriate;

(c) Sensitivity of State Estimator results with respect to variations in input parameters;

(d) Reasonable safeguards to assure State Estimator results are calculated on a non-discriminatory basis; and

(e) Other parameters as deemed appropriate.

**3.10.9.2 State Estimator Data**

(1) ERCOT uses a State Estimator to produce Load flow base cases, which are used to analyze the reliability of the ERCOT Transmission Grid. Accurate and redundant telemetry and an accurate transmission power system model are required by the State Estimator in order to produce an optimal estimation of the transmission power system state. State Estimator results are used in contingency analysis, congestion management, and other network analysis Real-Time sequence functions.

**3.10.9.3 Telemetry Status and Analog Measurements Data**

(1) Good telemetry status and analog measurements data for the transmission power system together with an accurate model of the ERCOT System are processed by the State Estimator to provide an optimal estimate of the ERCOT System state at a given point in time while filtering minor measurement errors and detecting gross errors. The quality and availability of telemetry provided to ERCOT is important to the performance of the ERCOT State Estimator.

(2) Telemetry is not needed at every node of the ERCOT System to arrive at a good estimate of the ERCOT System’s state. State Estimator performance must meet the performance requirements set forth in Section 3.10.9.4, State Estimator Performance Requirements, unless otherwise provided for in the Operating Guides.

(3) Beyond general telemetry performance criteria there are more stringent criteria needed at locations where state estimates are critically important, including, but not limited to, locations where reliability, security, and market impacts are of heightened concern.

**3.10.9.4 State Estimator Performance Requirements**

(1) The State Estimator shall converge 98% of runs during a one month period.

(2) For MW flows on Transmission Elements identified by ERCOT as causing 80% of congestion costs in the latest year for which data is available, the residual difference between State Estimator results and power flow results shall be less than 3% of the associated element Emergency Rating on at least 95% of samples measured in a one month period.

(3) For Transmission Elements identified by ERCOT as causing 80% of all congestion costs in the latest year for which data is available, the difference between the telemetry value (MW) and the State Estimator value (MW) shall be less than 3% of the associated element Emergency Rating on at least 95% of samples measured in a one month period.

(4) For the 20 most important station voltage points, as designated by ERCOT and approved by ROS, the telemetered voltage minus State Estimator voltage shall be within 2% of the telemetered voltage measurement for at least 95% of samples measured during a one month period.

(5) For all Transmission Elements 100 kV and above, the difference between the State Estimator solution (MW) and the SCADA measurement will be less than ten MW or 10% of the associated Emergency Rating (whichever is greater) on 99.5% of samples measured during a one month period. ERCOT shall report all equipment failing this test to the associated TSP who shall repair such equipment no later than ten days following detection by ERCOT.

(6) ERCOT shall post the State Estimator performance requirements contained in this Section on the MIS Secure Area.

**3.10.9.5 ERCOT Directives**

(1) ERCOT shall work with the TSP or QSE to resolve telemetry and/or model problems in accordance with telemetry requirements prior to directing additional equipment.

(2) In the event of failure to meet the requirements in paragraphs (2) or (3) of Section 3.10.9.4, State Estimator Performance Requirements, ERCOT may direct additional telemetry to be installed on elements contributing most to 80% of congestion costs for the latest year for which data is available. If the TSP or QSE disputes the request for additional telemetry, pursuant to paragraph (4) of Section 3.10.7.5.9, ERCOT Requests for Telemetry, the TSP or QSE may provide an alternative proposal.

(3) ERCOT shall enforce the requirements of paragraph (5) of Section 3.10.7.5.2, Continuous Telemetry of the Real-Time Measurements of Bus Load, Voltages, Tap Position, and Flows, by alarming any sum of flow around a bus that is more than (a) 5% of the largest normal line rating connected to the bus, or (b) five MW, whichever is greater, and requesting that the applicable TSP or QSE correct the failure.

(4) ERCOT shall consider the quality codes sent by the data provider in determining how confidence factors are assigned for the data to be used in the State Estimator. Valid and manual quality codes as defined in Section 3.10.7.5.8.1, Data Quality Codes, shall be considered as good quality. Quality codes sent as not good quality shall be considered at a lower confidence.

**3.10.9.6 Telemetry and State Estimator Performance Monitoring**

(1) ERCOT shall monitor the performance of the State Estimator, Network Security Analysis, SCED, and LMP Calculator. ERCOT shall post a monthly report of these items on the MIS Secure Area. ERCOT shall notify affected TSPs and QSEs of any lapses of observability of the transmission system.

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| ***[NPRR857 and NPRR1240: Replace applicable portions of paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities for NPRR857; or upon system implementation for NPRR1240:]***  (1) ERCOT shall monitor the performance of the State Estimator, Network Security Analysis, SCED, and LMP Calculator. ERCOT shall post a monthly report of these items on the MIS Secure Area, except for reports of State Estimator convergence rates that ERCOT shall post on the ERCOT website. ERCOT shall notify affected TSPs, QSEs, or DCTOs of any lapses of observability of the transmission system. |

3.11 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 benefit that is reasonably expected to accrue from the project as demonstrated through the production cost savings test or the congestion cost savings test. The current set of financial assumptions upon which the revenue requirement calculations for these tests are based will be reviewed annually, updated as necessary by ERCOT, and posted on the ERCOT website. The expected economic benefits are based on chronological simulations 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, comparing simulations with and without the project. These market simulations are 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 these simulations for the entire 30 to 40 year expected life of the project. Therefore, the economic benefits are projected over the period for which simulations are feasible, which is the planning horizon established in Planning Guide Section 3.1.1.2, Regional Transmission Plan, and a qualitative assessment is made of whether the factors driving the economic benefits due to the project can reasonably be expected to continue.

(5) To determine the economic benefits of a proposed project under the production cost savings test, 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. Outputs from the market simulations described in paragraph (4) above will be used to provide an estimate of the expected reduction in total system-wide production cost due to the project. Other adequately quantifiable and ongoing direct and indirect costs and benefits to the transmission system attributable to the project may be considered as appropriate. If the levelized ERCOT-wide annual production cost savings equals or exceeds the first-year annual revenue requirement of the transmission project, the project will be deemed to demonstrate sufficient economic benefit and will be recommended. ERCOT will publish requested non-confidential modeling inputs, assumptions, and outputs utilized in the production cost savings test if that information can be feasibly provided.

(6) To determine the economic benefits of a proposed project under the congestion cost savings test, the revenue requirement of the capital cost of the project is compared to the expected system-wide consumer energy cost reduction resulting from the project over the expected life of the project. Outputs from the market simulations described in paragraph (4) above will be used to provide an estimate of the expected reduction in total system-wide consumer energy cost due to the project. In the market simulations, system-wide consumer energy cost will be calculated using hourly load in MWh multiplied by hourly load nodal energy prices in $/MWh. Other adequately quantifiable and ongoing direct and indirect costs and benefits to the transmission system attributable to the project may be considered as appropriate. If the levelized system-wide consumer energy cost reduction equals or exceeds the average of the first three years’ annual revenue requirement for the project, the project will be deemed to demonstrate sufficient economic benefit and will be recommended. ERCOT will publish requested non-confidential modeling inputs, assumptions, and outputs utilized in the congestion cost savings test if that information can be feasibly provided.

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.

3.11.4.1.1 Project Submissions Based on Unsubstantiated Load

(1) Following the submission of a project by a TSP, if ERCOT determines that the asserted need for a Tier 1, Tier 2, or Tier 3 project is based in part or in whole on Unsubstantiated Load, ERCOT shall notify the submitting TSP and the RPG, and neither ERCOT nor the RPG will conduct any further review of the project.

**3.11.4.2 Project Comment Process**

(1) ERCOT shall conduct a comment process which is open to the stakeholders for all proposed Tier 1, 2 and 3 projects. The proposer of the project will have a reasonable period of time, as established by ERCOT, to answer questions and respond to comments submitted during this process. The Planning Guide provides details of this process.

**3.11.4.3 Categorization of Proposed Transmission Projects**

(1) ERCOT classifies all proposed transmission projects into one of four categories (or Tiers). Each Tier is defined so that projects with a similar cost and impact on reliability and the ERCOT market are grouped into the same Tier. For Tier classification, the total estimated cost of the project shall be used which includes costs borne by another party.

(a) A project shall be classified as Tier 1 if the estimated capital cost is greater than or equal to $100,000,000, unless the project is considered to be a neutral project pursuant to paragraph (f) below.

(b) A project shall be classified as Tier 2 if the estimated capital cost is less than $100,000,000 and a Certificate of Convenience and Necessity (CCN) is required, unless the project is considered to be a neutral project pursuant to paragraph (f) below.

(c) A project shall be classified as Tier 3 if any of the following are true:

(i) The estimated capital cost is less than $100,000,000 and greater than or equal to $25,000,000 and a CCN is not required, unless the project is considered to be a neutral project pursuant to paragraph (f) below; or

(ii) The estimated capital cost is less than $25,000,000, a CCN is not required, and the project includes 345 kV circuit reconductor of more than one mile, additional 345/138 kV autotransformer capacity, or a new 345 kV substation, unless the project is considered to be a neutral project pursuant to paragraph (f) below.

(d) A project with an estimated capital cost greater than or equal to $25,000,000 that is proposed for the purpose of replacing aged infrastructure or storm hardening shall be processed as a Tier 3 project and shall be reclassified as a Tier 4, neutral project upon ERCOT’s determination that any concerns, questions or objections raised during the comment process have been resolved satisfactorily.

(e) A project shall be classified as Tier 4 if it does not meet the requirements to be classified as Tier 1, 2, or 3 or if it is considered a neutral project pursuant to paragraph (f) below.

(f) A project shall be considered a neutral project if it consists entirely of:

(i) The addition of or upgrades to radial transmission circuits;

(ii) The addition of equipment that does not affect the transfer capability of a circuit;

(iii) Repair and replacement-in-kind projects;

(iv) Transmission Facilities needed to connect a new Generation Resource, Energy Storage Resource (ESR), or Settlement Only Generator (SOG) to a new or existing substation on the existing ERCOT Transmission Grid, including the substation;

(v) The addition of static reactive devices;

(vi) A project to serve a new Load, unless such project would create a new transmission circuit connection between two stations (other than looping an existing circuit into the new Load-serving station);

(vii) Replacement of failed equipment, even if it results in a ratings and/or impedance change; or

(viii) Equipment upgrades resulting in only ratings changes.

(2) ERCOT may use its reasonable judgment to increase the level of review of a proposed project (e.g., from Tier 3 to Tier 2) from that which would be strictly indicated by these criteria, based on stakeholder comments, ERCOT analysis or the system impacts of the project.

(a) A project with an estimated capital cost greater than or equal to $50,000,000 that requires a CCN shall be reclassified and processed as a Tier 1 project upon request by a Market Participant during the comment period per Planning Guide Section 3.1.5, Regional Planning Group Comment Process.

(3) Any project that would be built by an Entity that is exempt (e.g., a Municipally Owned Utility (MOU)) from getting a CCN for transmission projects but would require a CCN if it were to be built by a regulated Entity will be treated as if the project would require a CCN for the purpose of defining the Tier of the project.

(4) If during the course of ERCOT’s independent review of a project, the project scope changes, ERCOT may reclassify the project into the appropriate Tier.

**3.11.4.4 Processing of Tier 4 Projects**

(1) For any project classified in Tier 4, ERCOT will not solicit comments from RPG, conduct any independent review, or provide any endorsement for the project.

**3.11.4.5 Processing of Tier 3 Projects**

(1) ERCOT shall accept a Tier 3 project if no concerns, questions or objections are provided during the project comment process.

(2) If reasonable ERCOT or stakeholder concerns about a Tier 3 project cannot be resolved during the time period allotted by ERCOT, the project may be processed as a Tier 2 project, unless ERCOT assesses that reasonable progress is being made toward resolving these concerns.

**3.11.4.6 Processing of Tier 2 Projects**

(1) ERCOT shall conduct an independent review of a submitted Tier 2 project as follows:

(a) ERCOT’s independent review shall consist of studies and analyses necessary for ERCOT to make its assessment of whether the proposed project is needed and whether the proposed project is the preferred solution to the identified system performance deficiency that the project is intended to resolve;

(b) ERCOT shall consider all comments received during the project comment process and factor reasonable comments into its independent review of the project;

(c) ERCOT will attempt to complete its independent review for a project in 120 days or less. If ERCOT is unable to complete its independent review based on RPG input within 120 days, ERCOT shall notify the RPG of the expected completion time;

(d) ERCOT may, at its discretion, discuss submitted transmission projects at meetings of the RPG in order to obtain additional input into its independent review; and

(e) ERCOT shall prepare a written report documenting the results of its independent review and recommendation on the project and shall distribute this report to the RPG.

**3.11.4.7 Processing of Tier 1 Projects**

(1) ERCOT shall conduct an independent review of a submitted Tier 1 project as follows:

(a) ERCOT’s independent review will consist of studies and analyses necessary for ERCOT to make its assessment of whether the proposed project is needed and whether the proposed project is the preferred solution to the identified system performance deficiency that the project is intended to resolve;

(b) ERCOT will consider all comments received during the project comment process and factor reasonable comments into its independent review of the project;

(c) ERCOT will attempt to complete its independent review for a project in 150 days or less. If ERCOT is unable to complete its independent review based on RPG input within 150 days, ERCOT shall notify the RPG of the expected completion time;

(d) ERCOT may, at its discretion, discuss submitted transmission projects at meetings of the RPG in order to obtain additional input into its independent review; and

(e) ERCOT shall prepare a written report documenting the results of its independent review and recommendation on the project and shall distribute this report to the RPG.

(2) Tier 1 projects require ERCOT Board endorsement.

**3.11.4.8 Determine Designated Providers of Transmission Additions**

(1) Upon completion of an independent review, ERCOT shall determine the designated TSPs for any recommended transmission additions. The designated TSP for a recommended transmission addition will be the TSP that owns the end point(s) of the recommended transmission addition. The designated TSP can agree to provide the recommended transmission addition or delegate the responsibility to another TSP. If different TSPs own the two end points of a recommended transmission addition, ERCOT will designate them as co-providers of the recommended transmission addition, and they can decide between themselves what parts of the recommended transmission addition they will each provide. If they cannot agree, ERCOT will determine their responsibility following a meeting with the parties. If a designated TSP agrees to provide a recommended transmission addition but does not diligently pursue the recommended transmission addition (during the time frame before a CCN is filed, if required) in a manner that will meet the required in-service date, then upon concurrence of the ERCOT Board, ERCOT will solicit interest from TSPs through the RPG and will designate an alternate TSP.

**3.11.4.9 Regional Planning Group Acceptance and ERCOT Endorsement**

(1) For Tier 3 projects, successful resolution of all comments received from ERCOT and stakeholders during the project comment process will result in RPG acceptance of the proposed project. An RPG acceptance letter shall be sent to the TSP(s) for the project, the project submitter (if different from the TSP(s)), and posted on the Market Information System (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 (3) below. For Tier 1 projects, ERCOT’s endorsement is obtained upon affirmative vote of the ERCOT Board except as noted in paragraph (3) 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 (3) 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 a TSP asserts a need for a proposed Tier 1 or Tier 2 project based in part or in whole on its own planning criteria, then ERCOT’s independent review shall also consider whether a reliability need exists under the TSP’s criteria.  If ERCOT identifies a reliability need under the TSP’s criteria, then ERCOT shall recommend a project that would address that need as well as any reliability need identified under NERC or ERCOT criteria, but shall explicitly state in the independent review report that ERCOT has assumed the TSP’s criteria are valid and that an assessment of the validity of the TSP’s criteria is beyond the scope of ERCOT’s responsibility.  ERCOT or the ERCOT Board may provide a qualified endorsement of such a project if ERCOT determines that it is justified in part under ERCOT or NERC criteria, as described in paragraph (1) above.  However, neither ERCOT nor the ERCOT Board shall endorse a project that is determined to be needed solely to meet a TSP’s criteria.

**3.11.4.10 Modifications to ERCOT Endorsed Projects**

(1) If the TSP for an ERCOT-endorsed project determines a need to make a significant change to the facilities included in the project (such as the line endpoint(s), number of circuits, voltage level, decrease in rating or similar major aspect of the project), the TSP shall notify ERCOT of the details of that change prior to filing a CCN application, if required, or prior to beginning the final design of the project if no CCN application is required. If ERCOT concurs that the proposed change is significant, the change shall be processed as a Tier 3 project, unless ERCOT determines the project should more appropriately be processed in another Tier.

(2) For economic-driven projects, if a TSP determines that the estimated project cost has increased by more than 10% over the cost described in ERCOT’s endorsement, the TSP shall notify RPG prior to filing a CCN application if required, or prior to beginning the final design of the project if no CCN application is required, and provide an explanation for the cost increase. For comparison purposes, the cost of the route that best meets PUCT criteria will be used.

**3.11.4.11 Customer or Resource Entity Funded Transmission Projects**

(1)       If an affected TSP elects to pursue a Customer or Resource Entity funded transmission project that would have been classified as a Tier 1, Tier 2, or Tier 3 project for RPG Project Review, the TSP(s) shall conduct a reliability impact assessment of the proposed transmission project and shall submit a report summarizing the results of the reliability impact assessment for RPG Project Review.  Such projects shall be processed according to their Tier classification and shall be reclassified as a Tier 4, neutral project upon ERCOT’s determination that any concerns, questions or objections raised during the comment process have been resolved satisfactorily.

(2) ERCOT’s independent review of a Tier 1 or Tier 2 Customer or Resource Entity funded transmission project will be limited to assessing the reliability and congestion impact of the proposed project and submitting a report summarizing the results and findings to RPG for review and discussion. ERCOT will not endorse the project and will not present the project to the ERCOT Board. However, ERCOT may recommend the project not be implemented or recommend changes to the project scope if, in ERCOT’s sole discretion, the project negatively impacts the reliability or congestion of the ERCOT System.

(3) Customer or Resource Entity funded Tier 4 projects do not need to go through this review process.

3.11.5 Transmission Service Provider and Distribution Service Provider Access to Interval Data

(1) ERCOT shall provide specific interval data for Load and generation to TSPs and/or Distribution Service Providers (DSPs), upon request, in accordance with confidentiality as defined in Section 1.3, Confidentiality.

(a) The TSP’s and/or DSP’s request for interval data shall identify the reason for requesting the information in regards to impact to the planning process (e.g. build power flow cases, conduct a specific study, etc.).

(b) ERCOT shall evaluate the TSP and/or DSP request and validate reasons provided.

(c) Upon ERCOT validation of the TSP and/or DSP request, the data provided shall include meter data measured at points of injection and points of delivery which will measurably impact the TSP’s and/or DSP’s planning and operations as determined by ERCOT (e.g., determination of the TSP’s and/or DSP’s system Load or power flows).

(d) If ERCOT determines that the request is invalid and denies it, ERCOT shall provide the reasoning for denying the request.

3.11.6 Generation Interconnection Process

(1) The generation interconnection process facilitates the interconnection of new generation units in the ERCOT Region by assessing the transmission upgrades necessary for new generating units to operate reliably. The process to study interconnecting new generation or modifying an existing generation interconnection to the ERCOT Transmission Grid is covered in the Planning Guide. The generation interconnection study process primarily addresses the direct connection of generation Facilities to the ERCOT Transmission Grid and directly-related projects. Projects that are identified through this process and are regional in nature may be reviewed through the RPG Project Review process upon recommendation by the TSP or ERCOT, subject to the confidentiality provisions in Section 1.3, Confidentiality.

(2) ERCOT shall perform an independent economic analysis of the Transmission Facilities needed to connect a new Generation Resource, ESR, or SOG to a new or existing substation on the existing ERCOT Transmission Grid, including the substation, that are identified through this process that are expected to cost more than $25,000,000. This economic analysis is performed only for informational purposes; as such, no ERCOT endorsement will be provided. The results of the economic analysis shall be included in the interconnection study posting.

(3) Additional upgrades to the ERCOT Transmission Grid that might be cost-effective as a result of new or modified generation may be initiated by any stakeholder through the RPG Project Review procedure described in Section 3.11.4, Regional Planning Group Project Review Process, at the appropriate time, subject to the confidentiality provisions of the generation interconnection procedure.

3.12 Load Forecasting

(1) ERCOT shall produce and use Load forecasts to serve operations and planning objectives.

(a) ERCOT shall update and post hourly on the ERCOT website, a “Seven-Day Load Forecast” as described in Section 3.12.1, Seven-Day Load Forecast, that provides forecasted hourly Load over the next 168 hours for each of the Weather Zones and for each of the Forecast Zones.

(b) ERCOT shall develop and post monthly on the Market Information System (MIS) Secure Area a “36-Month Load Forecast” that provides a daily minimum and maximum Load forecast for the next 36 months for the ERCOT Region, for each of the Weather Zones, and for each of the Forecast Zones. The 36-Month Load Forecast is used in the Outage coordination process and for Resource adequacy reporting.

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| ***[NPRR1240: Replace paragraph (b) above with the following upon system implementation:]***  (b) ERCOT shall develop and post monthly on the ERCOT website a “36-Month Load Forecast” that provides a daily minimum and maximum Load forecast for the next 36 months for the ERCOT Region, for each of the Weather Zones, and for each of the Forecast Zones. The 36-Month Load Forecast is used in the Outage coordination process and for Resource adequacy reporting. |

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| ***[NPRR1004 and NPRR1240: Insert applicable portions of paragraph (c) below upon system implementation:]***  (c) ERCOT shall generate and post daily on the ERCOT website Load distribution factors that provide hourly distribution for non-Private Use Network Loads by means of the Mid-Term Load Forecast (MTLF). Private Use Network Loads will be generated separately. If ERCOT decides, in its sole discretion, to change the Load distribution factors for reasons such as anticipated weather events or holidays, ERCOT shall select representative conditions as an input reasonably reflecting the anticipated Load in the Operating Day. ERCOT may also modify the Load distribution factors to account for predicted differences in network topology between the Load forecast and Operating Day. ERCOT may set auto error correction settings and apply Load forecast validation to better represent Load Profiles. Private Use Network Load distribution factor data is redacted from the ERCOT website postings and all self-serve Load’s distribution factors are set to zero when the data is used by the downstream applications. |

(2) ERCOT shall produce and post to the ERCOT website an Intra-Hour Load Forecast (IHLF) that provides a rolling two hour five minute forecast of ERCOT-wide Load.

3.12.1 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.

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| ***[NPRR975: Insert paragraphs (a) and (b) below upon system implementation:]***  (a) ERCOT will use a variety of Load forecast models and will select the Load forecast model that best fits the expected conditions for each hour of the next 168 hours as the Seven-Day Load Forecast for that hour and may update this selection as expected conditions change.  (b) If the selected forecast used at the time of the Day-Ahead Reliability Unit Commitment (DRUC) for the peak Demand hour of any of the next seven days is above or below the average of the forecast models for that hour by the greater of 2000 MW or 4% of the average of the forecast models for that hour, ERCOT shall produce and post to the ERCOT website an explanation of why the outlier Load forecast model was selected for that hour. |

(2) The inputs for the Seven-Day Load Forecast are as follows:

(a) Hourly forecasted weather parameters for the weather stations within the Weather Zones, which are updated at least once per hour; and

(b) Training information based on historic hourly integrated Weather Zone Loads.

(3) ERCOT shall review the forecast suggested by Seven-Day Load Forecast and shall use its judgment, if necessary, to modify the result prior to implementation in the Ancillary Service Capacity Monitor, Day-Ahead Reliability Unit Commitment (DRUC), Hour-Ahead Reliability Unit Commitment (HRUC), and Resource adequacy reporting.

3.12.2 Study Areas

(1) ERCOT shall develop and use Study Areas for Load forecasting and study purposes, and will provide the Load forecast data to the market. A list of Study Areas shall be available on the ERCOT website.

3.12.3 Seven-Day Study Area Load Forecast

(1) ERCOT shall develop and post hourly on the ERCOT website a “Seven-Day Study Area Load Forecast” to predict the hourly Loads for the next 168 hours based on current weather forecast parameters within each Study Area.

(a) The forecast referenced in paragraph (1) above will not affect the values within the “Seven-Day Load Forecast” by Weather Zone and/or Forecast Zone.

3.13 Renewable Production Potential Forecasts

(1) ERCOT shall produce forecasts of Renewable Production Potential (RPP) for Wind-powered Generation Resources (WGRs) and PhotoVoltaic Generation Resources (PVGRs) to be used as an input into the Day-Ahead Reliability Unit Commitment (DRUC) and Hour-Ahead Reliability Unit Commitment (HRUC). ERCOT shall produce the forecasts using information provided by WGR/PVGR Entities, meteorological information, and Supervisory Control and Data Acquisition (SCADA). WGR and PVGR Entities shall install telemetry at their respective Resources and transmit the ERCOT-specified site-specific meteorological information to ERCOT. WGR and PVGR Entities shall also provide detailed equipment status at the WGR/PVGR facility as specified by ERCOT to support the RPP forecast. ERCOT shall post forecasts for each WGR and PVGR to the Qualified Scheduling Entities (QSEs) representing WGRs and/or PVGRs on the Market Information System (MIS) Certified Area. QSEs shall use the ERCOT-provided forecasts for WGRs/PVGRs throughout the Day-Ahead and Operating Day for applicable markets and Reliability Unit Commitments (RUCs). Similar requirements for run-of-the-river hydro must be developed as needed.

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| ***[NPRR1029: Replace paragraph (1) above with the following upon system implementation:]***  (1) ERCOT shall produce forecasts of Renewable Production Potential (RPP) for Wind-powered Generation Resources (WGRs), PhotoVoltaic Generation Resources (PVGRs), and the intermittent renewable generation component of each DC-Coupled Resource to be used as an input into the Day-Ahead Reliability Unit Commitment (DRUC) and Hour-Ahead Reliability Unit Commitment (HRUC). ERCOT shall produce the forecasts using information provided by WGRs, PVGRs, and DC-Coupled Resources; meteorological information; and Supervisory Control and Data Acquisition (SCADA). A Resource Entity with a WGR, PVGR, or DC-Coupled Resource shall install equipment to enable telemetry of site-specific meteorological information that ERCOT determines is necessary to produce the RPP forecast, and the Resource Entity’s QSE shall telemeter such information and Resource status information to ERCOT. ERCOT shall post forecasts for each WGR and PVGR and for the intermittent renewable generation component of each DC-Coupled Resource to the MIS Certified Area for the Qualified Scheduling Entity (QSE) representing that WGR, PVGR, or DC-Coupled Resource. QSEs shall use the ERCOT-provided forecasts for WGRs, PVGRs, and DC-Coupled Resources in the Day-Ahead and throughout the Operating Day for applicable markets and Reliability Unit Commitments (RUCs). Similar requirements for run-of-the-river hydro must be developed as needed. |

(2) ERCOT shall develop cost-effective tools or services to forecast energy production from Intermittent Renewable Resources (IRRs) with technical assistance from QSEs scheduling IRRs. ERCOT shall use its best efforts to develop accurate and unbiased forecasts, as limited by the availability of relevant explanatory data. ERCOT shall post on the ERCOT website objective criteria and thresholds for unbiased, accurate forecasts within five Business Days of change.

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| ***[NPRR1029: Replace paragraph (2) above with the following upon system implementation:]***  (2) ERCOT shall develop cost-effective tools or services to forecast energy production from Intermittent Renewable Resources (IRRs) and from the intermittent renewable generation component of each DC-Coupled Resource with technical assistance from QSEs representing such Resources. ERCOT shall use its best efforts to develop accurate and unbiased forecasts, as limited by the availability of relevant explanatory data. ERCOT shall post on the ERCOT website 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.

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| ***[NPRR885: Replace paragraph (1) above with the following upon system implementation:]***  (1) ERCOT shall procure Reliability Must-Run (RMR) Service, Must-Run Alternative (MRA) Service, Black Start Service (BSS), or Emergency Response Service (ERS) through Agreements. |

3.14.1 Reliability Must Run

(1) RMR Service is the use by ERCOT, under contracts with Resource Entities, of capacity and energy from Generation Resources that otherwise would not operate and that are necessary to provide voltage support, stability or management of localized transmission constraints under applicable reliability criteria, where market solutions do not exist.

(a) Upon receiving a Notification of Suspension of Operations (NSO) from a Resource Entity as described in Section 3.14.1.1, Notification of Suspension of Operations, ERCOT may begin procurement of RMR Service under this Section.

(b) Before entering into an RMR Agreement, ERCOT shall assess alternatives to the proposed RMR Agreement. ERCOT shall evaluate and present in a written report posted on the Market Information System (MIS) Secure Area the information in items (i) through (iv) below. ERCOT is not limited in the number of additional scenarios it chooses to evaluate. The written report shall include an explanation as to why the items below are insufficient, either alone or in combination, to fill the requirement that will be met by the potential RMR Unit. The report shall be posted in the time frame required under paragraph (5) of Section 3.14.1.2, ERCOT Evaluation Process. The list of alternatives ERCOT must consider includes (as reasonable for each type of reliability concern identified):

(i) Re-dispatch/reconfiguration through operator instruction;

(ii) Automatic Mitigation Plans (AMPs) and Remedial Action Plans (RAPs);

(iii) Remedial Action Schemes (RASs) initiated on unit trips or Transmission Facilities’ Outages; and

(iv) Any other operational alternatives deemed viable by ERCOT.

(c) ERCOT shall minimize the use of RMR Units as much as practicable subject to the other provisions of these Protocols. ERCOT may Dispatch an RMR Unit at any time for ERCOT System security.

(d) Each RMR Unit must meet technical requirements specified in Section 8.1.1.1, Ancillary Service Qualification and Testing.

(e) ERCOT may execute RMR Agreements for no less than one month and no more than one year, with one exception. ERCOT may execute an RMR Agreement for a term longer than 12 months if the Resource Entity must make a significant capital expenditure to meet environmental regulations or to ensure availability to continue operating the RMR Unit so as to make an RMR Agreement in excess of 12 months appropriate, in ERCOT’s opinion. The term of a multi-year RMR Agreement must take into account the appropriate RMR exit strategy discussed in Section 3.14.1.4, Exit Strategy from an RMR Agreement. In the event ERCOT chooses to contract for an RMR Unit for longer than one year, ERCOT shall annually re-evaluate the need for the RMR Unit under the criteria set forth in paragraph (b) above. If ERCOT determines the RMR Unit is no longer needed, ERCOT shall enter into exit negotiations with the contract signatories to attempt to exit the contract early. However, ERCOT shall not enter into such negotiations until a Market Notice is issued providing the anticipated RMR exit time frame. The RMR standard Agreement is included in Section 22, Attachment B, Standard Form Reliability Must-Run Agreement. ERCOT shall post each RMR Agreement in its entirety, including amendments or modifications thereto, within five Business Days of execution on the MIS Secure Area.

(f) A Generation Resource is eligible for RMR status based on criteria established by ERCOT indicating its operation is necessary to support ERCOT System reliability according to the Operating Guides. A combined-cycle generation Facility must be treated as a single unit for RMR purposes unless the combustion turbine and the steam turbine can operate separately. If the steam turbine and combustion turbine can operate separately, and the steam turbine is powered by waste heat from more than one combustion turbine, the combustion turbine accepted for RMR Service and a proportionate part of the steam turbine must be treated as a single unit for RMR purposes. If the combustion turbine accepted for RMR Service can operate separately from the steam turbine, and only the combustion turbine is accepted as an RMR Unit, the RMR energy price will be reduced by the value of the combustion turbine’s waste heat calculated at the Fuel Index Price (FIP), except when the steam turbine is Off-Line.

(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.

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| ***[NPRR1240: Replace paragraph (i) above with the following upon system implementation:]***  (i) ERCOT shall post on the ERCOT website all information relative to the use of RMR Units including energy deployed monthly. |

(j) The Resource Entity that owns or controls the RMR Unit may not use the RMR Unit for:

(i) Participating in the bilateral energy market;

(ii) Self-providing of energy except for plant auxiliary Load obligations under the RMR Agreement; and

(iii) Providing of Ancillary Service to any Entity.

(k) ERCOT shall issue a Market Notice on the need for an RMR Unit prior to entering negotiations for the RMR Unit. Such Market Notice shall include the link to the ERCOT final RMR evaluation, the Resource name and unit code, the name of the Resource Entity, the name of the Qualified Scheduling Entity (QSE) for the Resource, the Resource MW rating by Season, and potential duration of the RMR Agreement, including anticipated start and end dates.

(l) ERCOT shall, through the issuance of Market Notices, provide the same information, contemporaneously, about the need for, or elimination of an RMR Unit to all registered Market Participants, including QSEs and Resource Entities with RMR Units.

**3.14.1.1 Notification of Suspension of Operations**

(1) Except for the occurrence of a Forced Outage, a Resource Entity must notify ERCOT in writing no less than 150 days prior to the date on which the Resource Entity intends to cease or suspend operation of a Generation Resource for a period of greater than 180 days. If a Generation Resource is to be mothballed on a seasonal basis, the Resource Entity must notify ERCOT in writing no less than 90 days prior to the suspension date and identify its Seasonal Operation Period.

(2) The Resource Entity shall submit a completed Part I and Part II of the NSO (found in Section 22, Attachment E, Notification of Suspension of Operations). The Resource Entity may also complete Part III of the NSO and submit it along with Parts I and II, or may wait to submit Part III up to ten days after ERCOT makes a determination that the proposed suspension of the Generation Resource would result in a performance deficiency for which the Generation Resource has a material impact. Part I of the NSO must include the attestation of an officer of the Resource Entity that the Generation Resource is uneconomic to remain in service as currently designated and will be unavailable for Dispatch by ERCOT for a period specified in the NSO.

(3) A Resource Entity ceasing or suspending operations as a result of a Forced Outage lasting greater than 180 days shall notify ERCOT as soon as practicable by submitting an NSO. If an NSO is submitted for a Generation Resource that is suspending operations for greater than 180 days due to a Forced Outage but is not indefinitely or permanently ceasing operations, then:

(a) The Generation Resource will not be evaluated for RMR status;

(b) The NSO will not be posted on the ERCOT website, except that information contained in the NSO may be included in reports in accordance with Section 3.2.6.2.2, Total Capacity Estimate; and

(c) ERCOT will not issue a Market Notice.

(4) At least 60 days before the expiration of an existing RMR Agreement, the Resource Entity may apply to renew the RMR Agreement by submitting a new NSO (including both Part I and Part II). Upon receipt of such a renewal request, ERCOT shall update and post to the MIS Secure Area studies as set forth in Section 3.14.1, Reliability Must Run, within 15 Business Days.

**3.14.1.2 ERCOT Evaluation Process**

(1) Except as provided in paragraph (3) of Section 3.14.1.1, Notification of Suspension of Operations, upon receipt of an NSO under Section 3.14.1.1 ERCOT shall post the NSO on the ERCOT website and shall post on the MIS Secure Area all existing relevant studies and data and provide a Market Notice of the NSO and posting of the studies and data.

(2) Within 21 days after receiving the NSO described in paragraph (1) above, unless otherwise notified by ERCOT that a shorter comment period is required, Market Participants may submit comments to ERCOT on whether the Generation Resource(s) referenced in the NSO is necessary to support ERCOT System reliability or should qualify for a multi-year RMR Agreement. ERCOT shall consider and post all submitted comments on the MIS Secure Area.

(3) ERCOT shall conduct a reliability analysis of the need for any Generation Resource(s) with a summer Seasonal net max sustainable rating greater than or equal to 20 MW to support ERCOT System reliability. For Generation Resource(s) with a summer Seasonal net max sustainable rating less than 20 MW, ERCOT may conduct a reliability analysis if deemed appropriate by ERCOT following consultation with affected Transmission Service Provider(s) (TSP(s)).

(a) ERCOT shall use a Load forecast consistent with current Regional Transmission Plan assumptions and methodologies for the appropriate season(s). If additional new Generation Resources meet the criteria in Planning Guide Section 6.9, Addition of Proposed Generation to the Planning Models, ERCOT shall include those additional Generation Resources with the appropriate seasonal ratings.

(b) If the NSO indicates that the Generation Resource(s) will decommission or suspend operation, or in the case of a Forced Outage, has permanently ceased operation, ERCOT, in its sole discretion, may perform transmission reliability analysis over a planning horizon as defined by the available base cases but not to exceed two years.

(c) For purposes of the reliability analysis, ERCOT shall use the following criteria to identify a performance deficiency that is materially impacted by the Generation Resource:

(i) Without the Generation Resource, there are one or more Transmission Facilities loaded above their Normal Rating under pre-contingency conditions.

(ii) Without the Generation Resource, there is any instability or cascading for any of the following conditions:

(A) Pre-contingency;

(B) Normal system conditions followed by the contingency loss of a generating unit, transmission circuit, common tower outage, transformer, shunt device, or flexible alternating current transmission system (FACTS) device;

(C) Unavailability of a generating unit, followed by Manual System Adjustments, followed by the contingency loss of a generating unit, transmission circuit, common tower outage, transformer, shunt device, or FACTS device; or

(D) Unavailability of a 345/138 kV transformer, followed by Manual System Adjustments, followed by the contingency loss of a generating unit, transmission circuit, common tower outage, transformer, shunt device, or FACTS device.

(iii) Without the Generation Resource, there are one or more Transmission Facilities loaded above 110% of the Emergency Rating under normal system conditions followed by the contingency loss of a generating unit, transmission circuit, common tower outage, transformer, shunt device, or FACTS device.

(iv) For paragraphs (i) through (iii) above, the Generation Resource will only be deemed to have a material impact on a performance deficiency that is caused by a thermal overload(s) if the Generation Resource has a more than 2% unloading Shift Factor on the Transmission Facility(s) that is overloaded and more than 5% unloading impact on the Transmission Facility(s) that is overloaded. For purposes herein, an unloading impact is a measure of a reduction in flow on a Transmission Facility as a percent of its Rating due to a unit injection of power from the Generation Resource.

(v) ERCOT may, in its sole discretion, deviate from the above criteria in order to maintain ERCOT System reliability. However, ERCOT shall present its reasons for deviating from the above criteria to the Technical Advisory Committee (TAC) and ERCOT Board.

(d) ERCOT, in consultation with affected TSP(s), may rely upon the results of past planning studies to determine if the Generation Resource is necessary to support ERCOT System reliability. The past planning studies must have used the same or more restrictive reliability criteria than the criteria described in paragraph (c) above.

(e) Additionally, ERCOT shall conduct any other analysis (e.g., operations studies) as required and shall post all study data and results and all analyses and its determination on the MIS Secure Area and issue a Market Notice of its determination.

(4) Within 30 days after receiving the NSO, ERCOT shall issue a Market Notice indicating the status of the reliability analysis referenced in paragraph (3) above. The Market Notice will indicate one of the following:

(a) ERCOT has completed its reliability analysis and the Generation Resource is not required to support ERCOT System reliability;

(b) ERCOT has completed its reliability analysis and the analysis identifies a performance deficiency for which the Generation Resource has a material impact; or

(c) ERCOT has not completed its reliability analysis and will need additional time to complete the assessment.

(5) Within 60 days after receiving Part I and Part II of the NSO, ERCOT shall complete its reliability analysis described in paragraph (3) above and shall issue a Market Notice describing the results of its reliability analysis if the results were not provided in the Market Notice issued under paragraph (4) above. If ERCOT determines that the Generation Resource is not needed to support ERCOT System reliability, then the Generation Resource may cease or suspend operations according to the schedule in its NSO, unless ERCOT in its sole discretion permits the Generation Resource to suspend operations at an earlier date, and ERCOT shall note this in the Market Notice.

(6) Within ten days after a determination by ERCOT that the proposed suspension of the Generation Resource would result in a performance deficiency on which the Generation Resource has a material impact, as described in this Section, ERCOT shall issue a “Request for Proposal” (RFP) for Must-Run Alternatives (MRAs). ERCOT shall include in the RFP reasonably available information that would enable potential MRAs to assess the feasibility of submitting a proposal to provide a more cost‑effective alternative to the Generation Resource, including any known minimum technical requirements and/or operational characteristics required to eliminate the identified performance deficiency. The MRA RFP shall specify the expected number of hours that an MRA would be needed during the contract period, and the hours of the day, by season, that the MRA would be required to be available. ERCOT shall establish an RFP response schedule such that responses can be evaluated prior to 150 days after submittal of the NSO.

(7) Within ten days after a determination by ERCOT that the proposed suspension of the Generation Resource would result in a performance deficiency on which the Generation Resource has a material impact, as described in this Section, the Resource Entity shall, if it has not already done so, complete and submit to ERCOT Part III of the NSO (Section 22, Attachment E, Notification of Suspension of Operations). ERCOT shall post the Part III information on the ERCOT website. Concurrently, the Generation Resource shall submit an initial estimated budget used in the calculation of the proposed Standby Cost and RMR fuel adder, prepared in accordance with Section 3.14.1.11, Budgeting Eligible Costs, and Section 3.14.1.20, Budgeting Fuel Costs, to ERCOT. On or before the 11th day after the determination or the receipt of Part III of the NSO, whichever comes first, ERCOT and the Resource Entity shall begin good faith negotiations on an RMR Agreement. These negotiations shall include the budgeting process for Eligible Costs and for fuel costs as detailed in Section 3.14.1.11 and Section 3.14.1.20.

(8) ERCOT shall issue a Market Notice on the status of the RMR Unit or MRA, including the start date, duration of the RMR or MRA Agreement, the Standby Cost ($/Hour) as applicable, and the amount of MW under contract, within 24 hours of signing an RMR or MRA Agreement with a Resource Entity.

(9) Except in cases where the Generation Resource is to be mothballed on a seasonal basis, if, after 150 days following ERCOT’s receipt of Part I and Part II of the NSO, ERCOT has neither notified the Resource Entity that the continued operation of the Generation Resource is not required nor obtained ERCOT Board approval to enter into an RMR or MRA Agreement, then the Resource Entity may file a complaint with the Public Utility Commission of Texas (PUCT) under subsection (e)(1) of P.U.C. Subst. R. 25.502, Pricing Safeguards in Markets Operated by the Electric Reliability Council of Texas. If the Generation Resource is to be mothballed on a seasonal basis, then the Resource Entity may file such a complaint with the PUCT under subsection (e)(1) of P.U.C. Subst. R. 25.502 if ERCOT has neither notified the Resource Entity that the continued operation of the Generation Resource is not required nor obtained ERCOT Board approval to enter into an RMR Agreement within 90 days following ERCOT’s receipt of Part I and Part II of the NSO.

(10) If the ERCOT Board approves entering into an RMR Agreement but ERCOT and the Resource Entity have not both executed the RMR Agreement by the date on which the Resource Entity intends to cease or suspend operation of the Generation Resource, then the Resource Entity shall maintain that Generation Resource(s) so that it is available for Reliability Unit Commitment (RUC) commitment until no longer required to do so under subsection (e)(2) of P.U.C. Subst. R. 25.502. This paragraph does not apply to a Generation Resource that suspended operations due to a Forced Outage.

**3.14.1.2.1 ERCOT Evaluation of Seasonal Mothball Status**

(1) ERCOT shall evaluate requests to place Generation Resources on a seasonal mothball status pursuant to the guidelines provided in Section 3.14.1.2, ERCOT Evaluation Process, except as stated below.

(2) Within 30 days after receiving the NSO described in Section 3.14.1.1, Notification of Suspension of Operations, ERCOT shall issue a Market Notice indicating the status of the reliability analysis described in paragraph (3) of Section 3.14.1.2. The Market Notice will indicate one of the following:

(a) ERCOT has completed its reliability analysis and the Generation Resource is not required to support ERCOT System reliability during the portion of the year when the Generation Resource would be unavailable;

(b) ERCOT has completed its reliability analysis and the analysis identifies a performance deficiency for which the Generation Resource has a material impact during the portion of the year when the Generation Resource would be unavailable; or

(c) ERCOT has not completed its reliability analysis and will need additional time to complete the assessment.

(3) Within 60 days after receiving the NSO ERCOT shall complete its reliability analysis described in paragraph (3) of Section 3.14.1.2 and, if it has not already done so, ERCOT shall issue a Market Notice stating whether the Generation Resource is required to support ERCOT System reliability during the portion of the year when the Generation Resource would be unavailable.

**3.14.1.3 ERCOT Board Approval of RMR and MRA Agreements**

(1) If ERCOT determines that an RMR or MRA Agreement is a cost-effective solution to remedy a performance deficiency for which the suspending Generation Resource has a material impact as described in paragraph (3) of Section 3.14.1.2, ERCOT Evaluation Process, or if ERCOT has identified such a performance deficiency but has determined that entering into an RMR or MRA Agreement is not a cost-effective solution to that performance deficiency, then ERCOT shall present this finding to the ERCOT Board for approval. In seeking such approval, ERCOT shall stipulate to the ERCOT Board that:

(a) The Resource Entity provided a complete and timely NSO including a sworn attestation supporting its claim of pending Generation Resource closure;

(b) ERCOT received all of the data necessary to evaluate the need for and provisions of the RMR or MRA Agreement, and that information was posted on the MIS Secure Area by ERCOT as it became available to ERCOT;

(c) When executed, the signed RMR or MRA Agreement will comply with the ERCOT Protocols and be posted on the MIS Secure Area;

(d) ERCOT evaluated:

(i) The reasonable alternatives to a specific RMR Agreement as set forth in Section 3.14.1, Reliability Must Run, and compared the alternatives against the feasibility, cost and reliability impacts of the signed RMR Agreement;

(ii) The timeframe in which ERCOT expects each unit to be needed for reliability; and

(iii) The specific type and scope of reliability concerns identified for each RMR Unit or MRA as applicable.

(2) ERCOT shall execute the RMR or MRA Agreement as soon as feasible after receiving ERCOT Board approval to do so.

(3) ERCOT shall post on the MIS Secure Area, as they become available, unit-specific studies, reports, and data, by which ERCOT justified entering into the RMR or MRA Agreement.

**3.14.1.4 Exit Strategy from an RMR Agreement**

(1) No later than 90 days after the execution of an RMR Agreement, ERCOT shall report to the Board and post on the MIS Secure Area a list of feasible alternatives that may, at a future time, be more cost-effective than the continued renewal of the existing RMR Agreement. Through the ERCOT System planning process, ERCOT shall develop a list of potential alternatives to the service provided by the RMR Unit. At a minimum, the list of potential alternatives that ERCOT must consider include, building new or expanding existing Transmission Facilities, installing voltage control devices, soliciting or buying by auction interruptible Load from Retail Electric Providers (REPs), or extending the existing RMR Agreement on an annual basis. If a cost-effective alternative to the service provided by the RMR Unit is identified, ERCOT shall provide a proposed timeline to study and/or implement the alternative.

**3.14.1.5 Evaluation of Alternatives**

(1) In evaluating responses to the RFP for MRAs, ERCOT shall not consider any response that, in ERCOT’s sole opinion, does not facially demonstrate that the proposed MRA meets the eligibility requirements specified in Section 3.14.4.1, Overview and Description of MRAs, and the availability criteria and other conditions specified in the RFP for MRAs.

(2) ERCOT shall consider any of the following options to resolve an identified performance deficiency:

(a) The Generation Resource proposed for suspension of operations;

(b) All acceptable MRA proposals; and

(c) Any transmission upgrades that can be implemented prior to the time period for which the performance deficiency has been identified.

(3) ERCOT staff shall select the option or combination of options, if any, that most cost-effectively address the performance deficiency, as long as the cost of the selected options is justified given the possible impact to Customers due to the performance deficiency. If ERCOT determines that no option cost-effectively resolves the performance deficiency, then ERCOT shall not select any option. In selecting the most cost-effective option, ERCOT will consider the following factors:

(a) The degree to which the option addresses the identified performance deficiency;

(b) The total expected cost of each option;

(c) Expected unit performance of the Generation Resource proposed for suspension of operations, including start-up time, minimum run-time, minimum down-time, and historical unit outage data;

(d) Operational limitations of proposed MRAs, including start-up times, minimum run-times, ramp periods, and return-to-service times;

(e) Other operational constraints or operational benefits of the proposed option; and

(f) Any other factors which ERCOT determines are relevant to the evaluation, and for which ERCOT can develop quantifiable criteria with which to evaluate all proposed options.

(4) In evaluating the expected impact to Customers due to the performance deficiency, ERCOT shall consider the following factors:

(a) Expected amount of Customer Demand affected (MWh);

(b) Expected number of hours during which Customers will be affected;

(c) Number of Customers affected;

(d) Possible additional Customer impacts due to unforeseen conditions, such as Generation Resource unavailability, transmission circuit Outages, or Load variation due to extreme weather; and

(e) Potential economic impact to Customers.

(5) ERCOT staff shall recommend the selected option or options to the ERCOT Board of Directors for approval, or shall recommend that the ERCOT Board of Directors decline to accept any option, if no eligible, cost-effective option has been identified. ERCOT staff shall provide sufficient information to justify its recommendation. The ERCOT Board of Directors may approve or reject the proposed recommendation, or may direct ERCOT staff to pursue an agreement to procure one or more options not proposed by ERCOT staff.

**3.14.1.6 Transmission System Upgrades Associated with an RMR and/or MRA Exit Strategy**

(1) This Section applies only to RMR exit strategies corresponding to specific RMR or MRA Agreements that have not been terminated.

(a) ERCOT and the TSP(s) responsible for constructing any upgrades to the Transmission Facilities that are part of an RMR or MRA exit strategy shall coordinate construction clearances necessary to allow timely completion of all planned Transmission Facilities upgrades.

(b) The TSP(s) responsible for constructing upgrades to the Transmission Facilities that are part of an RMR or MRA exit strategy shall establish and send to ERCOT estimated Outage information, including completion dates and associated model information to ERCOT per Section 3.1.4, Communications Regarding Resource and Transmission Facilities Outages. For purposes of this Section, a Transmission Facility upgrade will be considered initiated upon the TSP authorizing any expenditures on the upgrade including, but not limited to, material procurement, right-of-way acquisition, and regulatory approvals.

(c) Upon initiation of the project, the TSP(s) responsible for constructing upgrades relating to the Transmission Facilities that are part of an RMR or MRA exit strategy shall provide to ERCOT monthly updates of the project’s status, noting any acceleration or delay in planned completion date. ERCOT shall report this data through the MIS as described in Section 12.2, ERCOT Responsibilities. Within 60 days of the completion date shown in the Notice provided per Section 3.1.4, for the Transmission Facilities upgrades, the TSP shall coordinate more timely updates if the timeline changes significantly.

(d) Within ten Business Days after completion of the Transmission Facilities upgrades that are part of an RMR or MRA exit strategy, ERCOT shall publish a Market Notice of such completion and the effective date of termination of the associated RMR or MRA Agreement.

**3.14.1.7 RMR or MRA Contract Termination**

(1) This Section applies only to RMR exit strategies corresponding to specific RMR or MRA Agreements that have not been terminated.

(2) Once a suitable RMR or MRA exit strategy has been developed as defined in Section 3.14.1.4, Exit Strategy from an RMR Agreement, and the strategy has been approved by the ERCOT Board and the affected TSP(s), the TSP(s) responsible for the Transmission Facilities upgrades, when requested by ERCOT, shall submit to ERCOT:

(a) A preliminary construction outage schedule necessary to complete the Transmission Facilities upgrades. Submissions, changes, approvals, rejections, and withdrawals regarding the preliminary construction outage schedule shall be processed through the ERCOT Outage Scheduler on the ERCOT MIS. Such construction outage schedule shall be updated monthly; or

(b) A Certificate of Convenience and Necessity (CCN) application timeline for projects requiring such PUCT certification. Once a CCN has been granted by the PUCT, the TSP(s) shall be required to meet the requirements in item (a) above.

(3) ERCOT shall review and approve or reject each construction outage schedule as provided in accordance with procedures developed by ERCOT in compliance with Section 3.1, Outage Coordination.

(4) The TSP(s) responsible for the Transmission Facilities upgrades that are part of an RMR or MRA exit strategy shall provide to ERCOT a project status and an estimated project completion date within five Business Days of ERCOT’s request.

(5) If ERCOT determines that a mutually agreeable preliminary construction outage schedule can be accommodated during the fall, winter, or spring, ERCOT and the TSP shall collaborate to determine if the 90 day termination notice for the RMR and/or MRA can be issued as soon after the summer load Season of the preceding year as possible and publish a Market Notice of these terminations. ERCOT and the TSP may give consideration to the risk of the decision to terminate the RMR and/or MRA Agreement and any options, such as RAPs and/or Mitigation Plans that could be used to mitigate transmission construction delays.

**3.14.1.8 RMR and/or MRA Contract Extension**

(1) This Section applies only to RMR exit strategies corresponding to specific RMR or MRA Agreements that have not been terminated.

(a) Forty-five days prior to the termination date of an existing RMR or MRA Agreement, pursuant to the 90-day termination notice as described in paragraph A(2) of Section 3, Term and Termination, of Section 22, Attachment B, Standard Form Reliability Must-Run Agreement, ERCOT shall assess the likelihood of completion of the Transmission Facilities upgrade project(s) or other exit strategies necessary to allow termination of an existing RMR or MRA Agreement based on the updates of project status provided by the TSP(s). If ERCOT determines that a delay in the termination date of the existing RMR or MRA Agreement is necessary to allow completion of the Transmission Facilities upgrade(s), it shall provide written Notice to the Resource Entity that owns or controls the RMR Unit or the QSE that represents the MRA of its intent to execute an extension to the existing RMR or MRA Agreement no later than 30 days prior to the planned termination date. Within 24 hours of ERCOT providing this Notice to the Resource Entity that owns or controls the RMR Unit or the QSE that represents the MRA, ERCOT shall issue a Market Notice on its intent to execute an extension to the existing RMR or MRA Agreement. The Market Notice must contain the name and seasonal MW ratings of the RMR Unit or MRA and the expected duration of the contract extension, including the expected termination date. ERCOT shall notify the ERCOT Board of the extension at the ERCOT Board’s next regularly scheduled meeting.

(b) Forty-five days prior to the expiration date of an existing RMR or MRA Agreement for which the Resource Entity that owns or controls the RMR Unit or the QSE that represents the MRA has applied for renewal, ERCOT shall assess the likelihood of completion of the Transmission Facilities upgrade project(s) necessary to eliminate the reliability need for a Resource with an existing RMR or MRA Agreement based on the updates of project status provided by the TSP(s). If ERCOT determines that an extension of the existing RMR or MRA Agreement of no more than 90 days would allow completion of the Transmission Facilities upgrade(s), it shall provide written Notice to the Resource Entity that owns or controls the RMR Unit or the QSE that represents the MRA of its intent to execute an extension to the existing RMR or MRA Agreement no later than 30 days prior to the planned expiration date. Within 24 hours of ERCOT providing this Notice to the Resource Entity that owns or controls the RMR Unit or the QSE that represents the MRA, ERCOT shall issue a Market Notice on its intent to execute an extension to the existing RMR or MRA Agreement. The Market Notice must contain the name and seasonal MW ratings of the RMR Unit or MRA and the expected duration of the contract extension, including the expected termination date. ERCOT shall notify the ERCOT Board of the extension at the ERCOT Board’s next regularly scheduled meeting.

(c) ERCOT may extend the existing RMR or MRA Agreement as necessary to allow completion of the Transmission Facilities upgrade(s), but in no event shall the extension last more than 90 days from the termination or expiration date of the existing RMR or MRA Agreement.

(d) Forty-five days prior to the end of the period for which the existing RMR or MRA Agreement has been extended, ERCOT shall assess whether the transmission upgrades are likely to be completed. If ERCOT determines that the upgrades are not likely to be completed, ERCOT shall enter into negotiations with the Resource Entity that owns or controls the RMR Unit or the QSE that represents the MRA to negotiate a new RMR or MRA Agreement to allow completion of the planned transmission upgrades. ERCOT shall issue a Market Notice on or before the date that extension negotiations begin with the Resource Entity that owns or controls the RMR Unit or the QSE that represents the MRA. The Market Notice must contain the name and seasonal MW ratings of the RMR Unit or MRA and the expected duration of the contract extension, including the expected termination date. Additionally, the Market Notice must contain a description of the exit strategy and the status of progress of exit strategy projects. ERCOT shall notify the ERCOT Board of the extension at the ERCOT Board’s next regularly scheduled meeting.

**3.14.1.9 Generation Resource Status Updates**

(1) By April 1st and October 1st of each year and when material changes occur, every Resource Entity that owns or controls a Mothballed Generation Resource or an RMR Unit shall report to ERCOT, on a unit-specific basis, the estimated lead time required for each Resource to be capable of returning to service and, in percentage terms, report probable generation capacity from each Resource that the Resource Entity expects to return to service in each Season of each of the next ten years.

(2) For modeling purposes, ERCOT and TSPs shall rely on the most recent submittal of the following two Notifications with respect to an RMR Unit, Mothballed Generation Resource or Decommissioned Generation Resource: Section 22, Attachment E, Notification of Suspension of Operations, or Section 22, Attachment H, Notification of Change of Generation Resource Designation. Except in the case of an NSO submitted for a Generation Resource temporarily suspending operation due to a Forced Outage, ERCOT shall post each submitted NSO and Notification of Change of Generation Resource Designation to the ERCOT website and issue a Market Notice notifying Market Participants of the posting as soon as practicable, but no later than five Business Days after receipt.

(3) A Mothballed Generation Resource that is not mothballed indefinitely shall remain modeled in all ERCOT systems at all times, (i.e., will not be flagged as “mothballed” in ERCOT’s models) and, when it is not available, the Resource Entity shall designate the Generation Resource as on Planned Outage in the Outage Scheduler.

(4) Except for Mothballed Generation Resources that operate under a Seasonal Operation Period, a Resource Entity with a Mothballed Generation Resource shall notify ERCOT in writing no less than 30 days prior to the date on which the Resource Entity intends to return a Mothballed Generation Resource to service by completing a Notification of Change of Generation Resource Designation.

(5) A Resource Entity must submit a Notification of Change of Generation Resource Designation no later than 60 days prior to the conclusion of an RMR Agreement.

(6) A Resource Entity with a Mothballed Generation Resource that operates under a Seasonal Operation Period shall notify ERCOT in writing no less than 15 days prior to the date on which the Resource Entity intends to begin its Seasonal Operation Period if the first date of operation is prior to the date designated by the Resource Entity in its NSO. A Resource Entity with a Mothballed Generation Resource that operates under a Seasonal Operation Period shall notify ERCOT in writing no less than 15 days prior to the end date designated by the Resource Entity in its NSO if the Resource Entity intends to suspend operation later than that date. Notifications under this Section shall be provided by the Resource Entity by completing a Notification of Change of Generation Resource Designation form (Section 22, Attachment H).

(7) Once the Resource Entity notifies ERCOT that a Mothballed Generation Resource is operating under a Seasonal Operation Period, the Resource Entity does not need to annually notify ERCOT of such status.

(8) A Resource Entity with a Mothballed Generation Resource operating under a Seasonal Operation Period shall notify ERCOT in writing no less than 15 days prior to the date on which the Resource Entity intends to return the Mothballed Generation Resource to year-round operation by completing a Notification of Change of Generation Resource Designation form (Section 22, Attachment H).

(9) A Resource Entity with a Mothballed Generation Resource that is not currently mothballed indefinitely must notify ERCOT in writing, by completing an NSO (Section 22, Attachment E), no less than 150 days before the date on which the Mothballed Generation Resource is to be suspended indefinitely or retired and decommissioned.

(10) ERCOT may request that a Mothballed Generation Resource operating under a Seasonal Operation Period be available for operation earlier than June 1st or later than September 30th of any given calendar year. If ERCOT identifies a specific Resource Entity or QSE with which it will discuss such a request in an attempt to reach a mutually agreeable resolution, ERCOT shall issue a Notice as soon as practicable. The Notice shall include the Resource name and, as applicable, the Resource mnemonic, the Resource MW rating by Season, and the potential duration of the extended operation period, including anticipated start and end dates. If agreement is reached for the Mothballed Generation Resource to be available for operation earlier than June 1st or later than September 30th, the Resource Entity shall complete, within two Business Days, a Notification of Change of Generation Resource Designation form (Section 22, Attachment H).

(11) If ERCOT and the Resource Entity or QSE cannot reach a mutual agreement to make the Mothballed Generation Resource operating under a Seasonal Operation Period available earlier than June 1st or later than September 30th of any given calendar year, then ERCOT may exercise its ability to bring the Mothballed Generation Resource operating under a Seasonal Operating Period into the market under an RMR Agreement pursuant to paragraph (4) of Section 6.5.1.1, ERCOT Control Area Authority.

(12) ERCOT may evaluate, on an annual basis, Mothballed Generation Resources operating under a Seasonal Operation Period for RMR Service to address ERCOT System reliability during the portion of the year when the Mothballed Generation Resource would be unavailable.

(13) A Resource Entity that submitted an NSO as a result of a Forced Outage must notify ERCOT of its intent to return to service as soon as practicable by updating its status in the Outage Scheduler and Current Operating Plan (COP) and is not required to submit a Notification of Change of Generation Resource Designation.

(14) Before retiring and decommissioning either a Mothballed Generation Resource this is mothballed indefinitely or an RMR Unit that would otherwise become a Mothballed Generation Resource upon expiration of an RMR Agreement, a Resource Entity shall notify ERCOT of the expected retirement by submitting a completed Notification of Change of Generation Resource Designation form (Section 22, Attachment H). The date of retirement indicated on the form shall comply with the requirements of Section 3.10.1, Time Line for Network Operations Model Changes.

(15) If a Generation Resource is designated as decommissioned and retired pursuant to any of the above provisions, ERCOT will permanently remove the Generation Resource from the ERCOT registration systems in accordance with Section 3.10.1. Except as provided in paragraph (16) below, if a Resource Entity decides to bring a Decommissioned Generation Resource back to service at a later date, it will be considered a new Resource and must follow the Generator Interconnection or Modification (GIM) process detailed in the Planning Guide. If the Generation Resource is designated as mothballed, ERCOT and TSPs will consider the Generation Resource mothballed until the Resource Entity indicates a definitive return to service date pursuant to this Section.

(16) A Resource Entity may bring a Decommissioned Generation Resource back to service without following the GIM process if the operating characteristics of the Resource are materially identical to the characteristics of the Resource as it existed prior to the date of decommissioning and the Resource Entity submits a Notification of Change of Generation Resource Designation (Section 22, Attachment H) within three years of the date the Generation Resource was removed from the ERCOT Network Operations Model. The date of return proposed in the Notification must be a Network Operations Model load date that is no earlier than 45 days and no later than 180 days from the date of the Resource Entity’s Notification. ERCOT may delay the Network Operations Model load date based on the timing of the Resource Entity’s submission of complete Resource registration data. If the Resource Entity is not the Resource Entity that was associated with the Generation Resource at the time it was removed from the model, the Resource Entity shall provide ERCOT documentation that establishes the Resource Entity’s ownership of the Generation Resource.

(a) Notwithstanding the proposed date of return reflected in the Notification, as a condition for the synchronization of the Resource, ERCOT or the interconnecting Transmission and/or Distribution Service Provider (TDSP) may require any studies, testing, metering, or facility upgrades that ERCOT or the TDSP deem necessary for the reliable interconnection of the Resource, and ERCOT may require the Resource Entity to resolve any operational concern associated with the Resource. The TDSP may require the Resource Entity to compensate the TDSP for any required studies or upgrades in the same manner contemplated for new Generation Resources by the ERCOT Planning Guide, the TDSP’s tariff, and the Standard Generation Interconnection Agreement (SGIA).

(b) If ERCOT or the TDSP requires any studies, testing, metering or facility upgrades, or if ERCOT determines that operational concerns must be addressed, the Resource Entity must complete the commissioning process within 90 days of the date of synchronization, subject to any extension authorized by ERCOT for good cause.

(c) Any Generation Resource that returns to service pursuant to this paragraph is entitled to any exemption from ERCOT requirements that the Resource was entitled to at the time it was removed from the model if the exemption still exists under ERCOT rules.

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| ***[NPRR1246: Replace Section 3.14.1.9 above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  **3.14.1.9 Generation Resource/Energy Storage 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, a Mothballed Energy Storage Resource (ESR), 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, Mothballed ESR, or Decommissioned Generation Resource: Section 22, Attachment E, Notification of Suspension of Operations, or Section 22, Attachment H, Notification of Change of Resource Designation. Except in the case of an NSO submitted for a Resource temporarily suspending operation due to a Forced Outage, ERCOT shall post each submitted NSO and Notification of Change of Resource Designation to the ERCOT website 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 or Mothballed ESR that is not mothballed indefinitely shall remain modeled in all ERCOT systems at all times, (i.e., will not be flagged as “mothballed” in ERCOT’s models) and, when it is not available, the Resource Entity shall designate the Resource as on Planned Outage in the Outage Scheduler.  (4) Except for Mothballed Generation Resources and Mothballed ESRs that operate under a Seasonal Operation Period, a Resource Entity with a Mothballed Generation Resource or Mothballed ESR 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 or Mothballed ESR to service by completing a Notification of Change of Resource Designation.  (5) A Resource Entity must submit a Notification of Change of Resource Designation no later than 60 days prior to the conclusion of an RMR Agreement.  (6) A Resource Entity with a Mothballed Generation Resource or Mothballed ESR 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 or Mothballed ESR 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 Resource Designation form (Section 22, Attachment H).  (7) Once the Resource Entity notifies ERCOT that a Mothballed Generation Resource or Mothballed ESR 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 or Mothballed ESR 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 or Mothballed ESR to year-round operation by completing a Notification of Change of Resource Designation form (Section 22, Attachment H).  (9) A Resource Entity with a Mothballed Generation Resource or Mothballed ESR that is not currently mothballed indefinitely must notify ERCOT in writing, by completing an NSO (Section 22, Attachment E), no less than 150 days before the date on which the Mothballed Generation Resource or Mothballed ESR is to be suspended indefinitely or retired and decommissioned.  (10) ERCOT may request that a Mothballed Generation Resource or Mothballed ESR operating under a Seasonal Operation Period be available for operation earlier than June 1st or later than September 30th of any given calendar year. If ERCOT identifies a specific Resource Entity or QSE with which it will discuss such a request in an attempt to reach a mutually agreeable resolution, ERCOT shall issue a Notice as soon as practicable. The Notice shall include the Resource name and, as applicable, the Resource mnemonic, the Resource MW rating by Season, and the potential duration of the extended operation period, including anticipated start and end dates. If agreement is reached for the Mothballed Generation Resource or Mothballed ESR to be available for operation earlier than June 1st or later than September 30th, the Resource Entity shall complete, within two Business Days, a Notification of Change of 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 or Mothballed ESR operating under a Seasonal Operation Period available earlier than June 1st or later than September 30th of any given calendar year, then ERCOT may exercise its ability to bring the Mothballed Generation Resource or Mothballed ESR operating under a Seasonal Operating Period into the market under an RMR Agreement pursuant to paragraph (4) of Section 6.5.1.1, ERCOT Control Area Authority.  (12) ERCOT may evaluate, on an annual basis, Mothballed Generation Resources and Mothballed ESRs 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 or Mothballed ESR 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 Resource Designation.  (14) Before retiring and decommissioning either a Mothballed Generation Resource or Mothballed ESR is mothballed indefinitely or an RMR Unit that would otherwise become a Mothballed Generation Resource upon expiration of an RMR Agreement, a Resource Entity shall notify ERCOT of the expected retirement by submitting a completed Notification of Change of 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 or Mothballed ESR is designated as decommissioned and retired pursuant to any of the above provisions, ERCOT will permanently remove the Resource from the ERCOT registration systems in accordance with Section 3.10.1. Except as provided in paragraph (16) below, if a Resource Entity decides to bring a Decommissioned Generation Resource back to service at a later date, it will be considered a new Resource and must follow the Generator Interconnection or Modification (GIM) process detailed in the Planning Guide. If the Resource is designated as mothballed, ERCOT and TSPs will consider the Resource mothballed until the Resource Entity indicates a definitive return to service date pursuant to this Section.  (16) A Resource Entity may bring a Decommissioned Resource back to service without following the GIM process if the operating characteristics of the Resource are materially identical to the characteristics of the Resource as it existed prior to the date of decommissioning and the Resource Entity submits a Notification of Change of Resource Designation (Section 22, Attachment H) within three years of the date the Generation Resource was removed from the ERCOT Network Operations Model. The date of return proposed in the Notification must be a Network Operations Model load date that is no earlier than 45 days and no later than 180 days from the date of the Resource Entity’s Notification. ERCOT may delay the Network Operations Model load date based on the timing of the Resource Entity’s submission of complete Resource registration data. If the Resource Entity is not the Resource Entity that was associated with the Generation Resource at the time it was removed from the model, the Resource Entity shall provide ERCOT documentation that establishes the Resource Entity’s ownership of the Generation Resource.  (a) Notwithstanding the proposed date of return reflected in the Notification, as a condition for the synchronization of the Resource, ERCOT or the interconnecting Transmission and/or Distribution Service Provider (TDSP) may require any studies, testing, metering, or facility upgrades that ERCOT or the TDSP deem necessary for the reliable interconnection of the Resource, and ERCOT may require the Resource Entity to resolve any operational concern associated with the Resource. The TDSP may require the Resource Entity to compensate the TDSP for any required studies or upgrades in the same manner contemplated for new Generation Resources by the ERCOT Planning Guide, the TDSP’s tariff, and the Standard Generation Interconnection Agreement (SGIA).  (b) If ERCOT or the TDSP requires any studies, testing, metering or facility upgrades, or if ERCOT determines that operational concerns must be addressed, the Resource Entity must complete the commissioning process within 90 days of the date of synchronization, subject to any extension authorized by ERCOT for good cause.  (c) Any Resource that returns to service pursuant to this paragraph is entitled to any exemption from ERCOT requirements that the Resource was entitled to at the time it was removed from the model if the exemption still exists under ERCOT rules. |

**3.14.1.10 Eligible Costs**

(1) “Eligible Costs” are costs that would be incurred by the RMR Unit owner to provide the RMR Service, excluding fuel costs or other costs the RMR Unit would have incurred anyway had it been mothballed or shut down.

(a) Examples of Eligible Costs include the following to the extent they each meet the standard for eligibility:

(i) Direct labor to operate the RMR Unit during the term of the RMR Agreement;

(ii) Materials and supplies directly consumed or used in operation of the RMR Unit during the term of the RMR Agreement;

(iii) Services necessary to operate the RMR Unit during the term of the RMR Agreement;

(iv) Costs associated with emissions credits used as a direct result of operation of the RMR Unit under direction from ERCOT, or emissions reduction equipment as may be required according to terms of the RMR Agreement;

(v) Costs associated with maintenance:

(A) Due to required equipment maintenance;

(B) Due to replacement to alleviate unsafe operating conditions;

(C) Due to regulatory requirements, with compliance dates during the term of the RMR Agreement (any such compliance dates and requirements shall be explicitly defined in the RMR Agreement); or

(D) To ensure the ability to operate the RMR Unit consistent with Good Utility Practice;

(vi) Reservation and transportation costs associated with firm fuel supplies not recovered under Section 6.6.6.2, RMR Payment for Energy;

(vii) Property taxes and other taxes attributable to continuing to operate the RMR Unit during the term of the RMR Agreement;

(viii) General fund transfers or similar direct expenses incurred by a Municipally Owned Utility (MOU) if it is required to pay a portion of its revenues to the municipality. If the RMR payment to the MOU is subject to such a requirement, this expense is an incremental cost directly associated with the RMR Unit;

(ix) Costs based on a long-term service agreement (LTSA), provided that:

(A) The maintenance costs to be included are incremental and consistent with the definitions of the costs within the scope of the RMR Agreement and these Protocols;

(B) The cost of each component is specifically set by the LTSA;

(C) ERCOT must be able to verify the incremental or variable maintenance costs ($/MWh) or ($/start) described in the LTSA; and

(D) The LTSA is in effect during the term of the RMR Agreement and available to ERCOT for review; and

(x) Non-fuel costs to return a mothballed RMR Unit, or an RMR Unit that had ceased operations permanently due to a Forced Outage, to service provided that:

(A) The costs were incurred between the effective date of the RMR Agreement and the termination date of the RMR Agreement; and

(B) The costs do not include costs the RMR Unit owner would have incurred had the RMR Unit remained mothballed or under Forced Outage.

(b) Examples of costs not included as Eligible Costs are:

(i) Depreciation expense, return on equity, and debt and interest costs;

(ii) Property taxes and other taxes not attributable to continuing to operate the RMR Unit;

(iii) Income taxes of the RMR Unit owner or operator;

(iv) Labor and material costs associated with other, non-RMR Generation Resources at the same facility;

(v) Cost of parts inventory not used by the RMR Unit during the term of the Agreement;

(vi) Costs attributed to other Resources in the power generation station; and

(vii) Any other costs the Resource Entity that owns the RMR Unit would have incurred even if the RMR Unit had been mothballed or shutdown.

**3.14.1.11 Budgeting Eligible Costs**

(1) The owner of an RMR Unit shall provide a good faith preliminary budget, including detailed monthly estimates of its Eligible Costs to ERCOT, to support its calculation of the initial Standby Cost in Part III of the Notification of Suspension of Operations submitted to ERCOT pursuant to paragraph (4) of Section 3.14.1.2, ERCOT Evaluation Process, in a format acceptable to ERCOT. ERCOT shall review the budget and may reject any item it determines to be unreasonable. The owner of the RMR Unit and ERCOT may mutually agree to modify the expected contract capacity and Target Availability of the RMR Unit as necessary to account for any budget item that is rejected.

(2) As part of the MRA evaluation process, the QSE that represents the MRA must notify ERCOT if any contributed capital expenditures are required under the proposed MRA Agreement. The QSE that represents the MRA shall provide an explanation and a good faith preliminary budget for the contributed capital expenditures in a format acceptable to ERCOT. ERCOT shall review and may approve the budget to determine which costs would be considered contributed capital expenditures in accordance with Section 3.14.1.19, Charge for Contributed Capital Expenditures.

(3) ERCOT may retain a third party mutually agreeable to ERCOT and the owner of the RMR Unit to assist in the evaluation of a submitted budget, whether for initial or updated costs. The cost of such a third party will be allocated pursuant to paragraph (2) of Section 6.6.6.6, Method for Reconciling RMR Actual Eligible Costs, RMR and MRA Contributed Capital Expenditures, and Miscellaneous RMR Incurred Expenses.

(4) The Eligible Cost budgeting process is as follows:

(a) The RMR Unit owner shall supply ERCOT a preliminary Eligible Cost budget for the expected RMR Agreement period starting with the anticipated effective date of the RMR Agreement.

(b) The preliminary Eligible Cost budget should be submitted in conjunction with Part III of the NSO, as specified in paragraph (2) of Section 3.14.1.1, Notification of Suspension of Operations, and paragraph (6) of Section 3.14.1.2.

(c) The budget will include Eligible Costs categorized in terms of:

(i) Base Cost of Operations, by month, which includes Eligible Costs that are independent of the levels of operation, Outages and non-Outage maintenance;

(ii) Outage Maintenance Cost, which includes Eligible Costs attributable to Planned or Maintenance Outages and/or inspections occurring during the term of the RMR Agreement, by month. Maintenance alternatives available during any Planned or Maintenance Outage must be presented to ERCOT for determination of the alternative to be performed and paid for under the RMR Agreement. The RMR Unit owner must present ERCOT with a budget for each option, benefits of each alternative, unit availability impact associated with not performing each alternative, and a recommendation to facilitate ERCOT’s selection process. If no reasonable alternatives are available then the RMR Unit owner shall provide an affirmation to that effect;

(iii) Non-Outage Maintenance Cost, by month, which includes non-recurring Eligible Costs that are independent of a particular scheduled Outage. Non-Outage maintenance alternatives available during any scheduled Outage must be presented to ERCOT for determination of the alternative to be performed and paid for under the RMR Agreement. The RMR Unit owner must present ERCOT with a budget for each option, benefits of each alternative, unit availability impact associated with not performing each alternative, and a recommendation to facilitate ERCOT’s selection process. If no reasonable alternatives are available then an affirmation by the RMR Unit owner to that effect must be included in the RMR Agreement;

(iv) For Resources without approved verifiable costs, the following data is required:

(A) Variable Operations & Maintenance (O&M) costs ($/start), from start to Low Sustained Limit (LSL), for each start type:

(1) Cold;

(2) Hot; and

(3) Intermediate;

(B) Operating variable O&M costs ($/MWh):

(1) At LSL; and

(2) Above LSL;

(C) Average generation from breaker close to LSL (MWh), for each start type:

(1) Cold;

(2) Hot; and

(3) Intermediate;

(D) Fuel consumption (MMBtu/start), for each start type:

(1) Cold;

(2) Hot; and

(3) Intermediate;

(E) Startup Fuel Percentage from start to LSL, for each start type:

|  |  |  |  |
| --- | --- | --- | --- |
| Fuel Type | Hot (%) | Intermediate (%) | Cold (%) |
| Gas |  |  |  |
| Fuel Oil |  |  |  |
| Solid Fuel |  |  |  |

(F) Operating Fuel Percentage:

|  |  |  |
| --- | --- | --- |
| Fuel Type | At LSL | Above LSL |
| Gas |  |  |
| Fuel Oil |  |  |
| Solid Fuel |  |  |

(G) Input/output curve coefficients;

(v) Other budget items means Eligible Costs not clearly identifiable in the previous three categories including:

(A) Environmental emission credit consumption (or purchase as explicitly defined under the RMR Agreement, to operate the unit) includes the opportunity cost for using emission credits through the combustion of fuel feedstock by the RMR Unit. Costs must be based on verifiable market data as supplied by the RMR Unit owner; and

(B) “Compliance Costs,” which includes foreseeable costs to comply with regulations, Federal or state that have a compliance deadline that occurs during the term of the RMR Agreement.

(d) Thirty days after receipt of the preliminary Eligible Costs budget, ERCOT shall notify the RMR Unit owner of its selections under the alternatives provided in the preliminary budget. The RMR Unit owner and ERCOT shall set the Target Availability monthly values consistent with the options presented to and selected by during the budgeting process. The Target Availability shall be mutually agreed by ERCOT and the RMR Unit owner by taking into account a negotiated amount of predicted Forced Outages, Planned Outages identified during the budgeting process, and any budget items rejected by ERCOT.

(e) If applicable, the RMR Unit owner should provide a written description of the type of work needed for the Resource to achieve the operational conditions for the RMR Service, in accordance with the capacity and Target Availability requirements. This should include:

(i) A description of the equipment needed;

(ii) An indication if the equipment is anticipated to be expensed or capitalized;

(iii) The estimated life and depreciation schedule of each capitalized component;

(iv) The estimated salvage value of the capitalized components;

(v) The estimated time to install each piece of equipment; and

(vi) The expected time of completion of work needed to restore the Resource to operational status.

**3.14.1.12 Calculation of the Initial Standby Cost**

(1) The initial Standby Cost shall be calculated by dividing the total monthly approved budget cost over the term of the RMR Agreement by the total hours for the term of the RMR Agreement.

**3.14.1.13** **Updated Budgets During the Term of an RMR Agreement**

(1) Upon commencement of the RMR Agreement, based on the Agreement term, the RMR Unit owner shall identify planned equipment installations as anticipated to be expensed or capitalized and shall update the estimated salvage value of capitalized components. The RMR Unit owner shall submit to ERCOT updated budget information every three months, in a format consistent with the preliminary budget, for the remainder of the term of the RMR Agreement. ERCOT shall review updated budget information for reasonableness and may reject any item it determines to be unreasonable. The owner of the RMR Unit and ERCOT may mutually agree to modify the contract capacity and Target Availability of the RMR Unit to account for any such budget item rejection.

(2) ERCOT will use approved updated budget information to update the total RMR costs expected to be incurred over the remaining term of the RMR Agreement. If the total costs over the remaining term of the RMR Agreement change by more than 10% with respect to those costs anticipated for the same period in the most recently approved budget, the RMR Standby Cost will be recalculated. The revised Standby Cost will be recalculated by dividing the remaining budgeted costs over the number of remaining hours for which the RMR Unit is under an RMR Agreement.

(3) ERCOT shall issue a Market Notice describing the revised Standby Cost at least ten calendar days prior to the effective date of a change to the Standby Cost. The effective date of a revised Standby Cost will always be on the first day of a calendar month.

**3.14.1.14 Reporting Actual RMR Eligible Costs**

(1) The RMR Unit owner shall provide ERCOT with documentation supporting actual Eligible Costs on a monthly basis in a form and a level of detail acceptable to ERCOT for ERCOT to verify that all Eligible Costs are actual and appropriate. Submitted actual Eligible Costs must be categorized consistently with budgeted Eligible Costs. Actual cost data must be submitted on time by the Resource Entity for the RMR Unit and then verified by ERCOT so the actual cost data can be reflected in the Final or True-Up Settlement Statement.

(2) To be considered timely for the final, actual cost data for month ‘x’ must be submitted by the 16th of the month following month ‘x’. To be considered timely for the true-up, actual cost data for month ‘x’ must be submitted 60 days prior to the publishing date of the True-Up Settlement Statement for the first day in month ‘x’. Any deviation in filing actual cost data in accordance with this calendar must be requested of ERCOT, by the QSE representing an RMR Unit. Such request for deviation shall contain the reason for the inability to meet the calendar and an expected date that the cost data will be provided to ERCOT. At its discretion ERCOT may choose to honor such a request. No later than two Business Days following its decision, ERCOT shall issue a Market Notice of any such request and its response thereto. In the event, that actual cost data is not submitted in accordance with the calendar or approved deviation for the true-up, then the cost for the portion of eligible cost that has not been submitted is deemed to be zero.

**3.14.1.15 Reporting Actual MRA Eligible Costs**

(1) The QSE that represents the MRA that has received contributed capital expenditures shall provide ERCOT with evidence of the actual costs associated with the capital expenditures on a monthly basis in a level of detail sufficient for ERCOT to verify that all capital contributions costs are actual and appropriate.

**3.14.1.16 Reconciliation of Actual Eligible Costs**

(1) ERCOT shall issue a miscellaneous Invoice to charge the QSE representing the RMR Unit for any identified over-payments for actual Eligible Costs. Funds collected will be distributed in accordance with Section 6.6.6.6, Method for Reconciling RMR Actual Eligible Costs, RMR and MRA Contributed Capital Expenditures, and Miscellaneous RMR Incurred Expenses.

**3.14.1.17 Incentive Factor**

(1) Subject to the reductions described in paragraphs (2) and (3) below, the Incentive Factor for RMR Agreements is equal to 10% of the actual Eligible Costs, excluding fuel costs and reservation and transportation costs associated with firm fuel supplies as described in paragraph (1)(a)(vi) of Section 3.14.1.10, Eligible Costs. The Incentive Factor for RMR Agreements is not applied to capital expenditures as described in Section 3.14.1, Reliability Must Run, or to capital expenditures reclassified as an expense in accordance with paragraph (3)(d) of Section 3.14.1.19, Charge for Contributed Capital Expenditures. The Incentive Factor shall never be less than zero.

(2) The Incentive Factor shall be reduced if the RMR Unit fails to perform to the contracted capacity during a Capacity Test as described in the RMR Agreement. The reduction will be linear, with a 2% reduction in the Incentive Factor for every 1% of reduced Capacity.

(3) The Incentive Factor shall be reduced if the “Hourly Rolling Equivalent Availability Factor” of the RMR Unit is less than the Target Availability (i.e. the “Actual Availability”, as defined below, is less than the Target Availability).

(a) The reduction will be linear; with a 2% reduction in the Incentive Factor payment for every 1% of the Hourly Rolling Equivalent Availability Factor less than the Target Availability stated in the RMR Agreement. The RMR Unit’s Actual Availability shall be calculated on an hourly rolling six-month average basis.

(b) The calculation is made by dividing the total MW of available capacity per hour according to its final COP by the total MW of contracted capacity per hour for the previous 4380 hours.

(c) For purposes of this calculation, any hour within the previous 4380-hour period that precedes the start date of the RMR Agreement is treated as if 100% of the capacity of the unit was available for the hour.

**3.14.1.18 Major Equipment Modifications**

(1) During the term of an RMR Agreement, in the event that major equipment modifications are required in order for the RMR Unit to provide RMR Service (such as installation of environmental control equipment), ERCOT and the RMR Unit owner shall negotiate in good faith concerning changes to the terms of the RMR Agreement.

**3.14.1.19 Charge for Contributed Capital Expenditures**

(1) This Section applies to any RMR or MRA Agreement entered into by ERCOT and a Resource Entity or QSE on or after October 12, 2016.

(2) For purposes of this Section, contributed capital expenditures are defined as expenditures that were made to ensure the availability of an RMR Unit or MRA in connection with an RMR or MRA Agreement, that were settled in accordance with the Settlement processes in the ERCOT Protocols, and that would ordinarily be capitalized under Generally Accepted Accounting Principles (GAAP) or International Accounting Standards (IAS) assuming ongoing operation of the RMR Unit or MRA. Consistent with the process described in Section 3.14.1.11, Budgeting Eligible Costs, ERCOT will identify contributed capital expenditure items included in each category of submitted Eligible Costs as defined in Section 3.14.1.10, Eligible Costs, or submitted with any MRA budgets.

(3) A QSE that has received payments from ERCOT for contributed capital expenditures pursuant to an RMR or MRA Agreement entered into on or after October 12, 2016 must refund to ERCOT the contributed capital expenditures as follows:

(a) At the end of the RMR Agreement, if the Resource Entity chooses not to have the Generation Resource participate in energy or Ancillary Service markets, the QSE representing the Resource Entity shall repay, in a lump sum payment, the positive salvage value associated with the contributed capital expenditures, as estimated at the time of the RMR Agreement.

(b) At the end of the MRA Agreement, if the QSE that represents the MRA chooses not to have the MRA participate in energy or Ancillary Service markets, the QSE representing the MRA shall repay, in a lump sum payment, the positive salvage value associated with the contributed capital expenditures, as estimated at the time of the MRA Agreement. In addition, the QSE that represents the MRA must repay, in a lump sum payment, the value of contributed capital expenditures in excess of the actual cost of the capitalized equipment.

(c) If an RMR Unit or MRA participates in the energy or Ancillary Service markets at any time after the termination date of the RMR or MRA Agreement, the Resource Entity that owns or controls the RMR Unit or the QSE that represents the MRA shall repay, in a lump sum payment, 100% of the remaining book value of the capitalized equipment and capitalized installation charges based on straight-line depreciation over the estimated life of the capitalized component(s) as of the termination date of the RMR or MRA Agreement in accordance with GAAP or IAS standards for electric utility equipment, plus 10% of the value of any accelerated tax depreciation associated with the capital contribution taken by the Resource Entity that owns or controls the RMR Unit or the QSE that represents the MRA during the term of the RMR or MRA Agreement, less any remaining positive salvage value associated with the contributed capital expenditures that was previously repaid in accordance with paragraph (a) or (b) above. The estimated life shall be based on documentation provided by the manufacturer; or, if installing used equipment, the estimated life may be based on an approximation agreed to by the Resource Entity that owns or controls the RMR Unit or the QSE that represents the MRA and ERCOT, but in no event shall the estimated life be less than the equipment life used for federal income tax purposes. The value of the accelerated tax depreciation for each year shall be the difference between the straight line figure and the appropriate Modified Accelerated Cost Recovery System (MACRS) depreciation schedule for the equipment, multiplied by the statutory tax rate. The calculation of the accelerated depreciation as described herein must be supported by an attestation executed by an officer or executive with the authority to bind the Resource Entity or the QSE representing the Resource Entity.

(d) If additional contributed capital expenditures are identified subsequent to execution and during the term of the RMR or MRA Agreement, the applicable repayment amounts as determined in paragraphs (a), (b), or (c) above will be modified accordingly.

(e) The amount of contributed capital expenditures may be adjusted by ERCOT when early termination in accordance with the RMR Agreement results in a reclassification of capital expenditures to expenses in accordance with GAAP or IAS.

(f) If the Resource Entity that owns or controls the RMR Unit or the QSE that represents the MRA is required to pay a lump sum payment of contributed capital expenditures per paragraph (a), (b), or (c) above, then ERCOT will issue a Market Notice identifying the amount of the lump sum payment within five Business Days of termination of the RMR or MRA Agreement.

(i) ERCOT shall issue a miscellaneous Invoice charging the QSE for the applicable amounts under paragraphs (a), (b), or (c) above. ERCOT will issue a Market Notice after completion of the collection and disbursement of the repaid contributed capital expenditures.

(ii) ERCOT shall distribute the repayment to QSEs representing Load per Section 6.6.6.6, Method for Reconciling RMR Actual Eligible Costs, RMR and MRA Contributed Capital Expenditures, and Miscellaneous RMR Incurred Expenses.

**3.14.1.20 Budgeting Fuel Costs**

(1) The RMR Unit owner shall supply ERCOT a preliminary monthly fuel cost budget for the anticipated term and effective date of the RMR Agreement. The fuel cost budget must include information pertaining to the cost of the fuel feedstock, including where appropriate transportation costs and terms, as well as fuel storage costs and terms, and any other fuel contract provisions (e.g. “take or pay” provisions) that may impact the cost of all fuels anticipated to be used by the RMR Unit over the life of the RMR Agreement and must include fuel costs categorized in terms of:

(a) Primary fuel; and

(b) Secondary fuel.

(2) The estimated fuel payments may include a fuel adder to better approximate expected fuel costs, which may be adjusted from time to time by mutual agreement of the RMR Unit owner and ERCOT. The fuel adder shall represent the difference between the forecasted average fuel price and the forecasted average of the relevant index price over the RMR contract period. The fuel adder must also include the forecasted cost of transporting and delivering fuel and fuel imbalance fees to the Resource. The RMR Unit owner must provide to ERCOT supporting documentation indicating how the fuel adder was determined.

(3) The RMR Unit owner shall provide good faith estimates of the RMR Unit input/output curve coefficients to ERCOT with its Notification of Suspension of Operations.

(4) Based on production figures provided to the RMR Unit owner by ERCOT, the RMR Unit owner shall also provide ERCOT fuel supply options available for the RMR Unit. For each option, the RMR Unit owner shall detail the associated impacts on the fuel and non-fuel budgets and on the availability of the RMR Unit. If no reasonable alternatives are available then an affirmation by the RMR Unit owner to that effect must be included in the RMR Agreement. If there are available fuel options, then no less than 30 days after the receipt of the fuel supply options, ERCOT shall notify the RMR Unit owner of its fuel supply option selection.

**3.14.1.21 Reporting Actual Eligible Fuel Costs**

(1) The RMR Unit owner shall provide ERCOT with actual fuel costs on a monthly basis for the RMR Unit in a level of detail sufficient for ERCOT to verify that all fuel costs are actual and appropriate. ERCOT shall perform a true-up of the estimated fuel costs using the submitted and verified actual fuel costs for the RMR Unit. Actual cost data must be submitted on time by the Resource Entity for the RMR Unit and then verified by ERCOT so the actual cost data can be reflected in the True-Up Settlement Statement. To be considered timely for the final, actual cost data for month ‘x’ must be submitted by the 16th of the month following month ‘x.’ To be considered timely for the true-up, actual cost data for month ‘x’ must be submitted 60 days prior to the publishing date of the True-Up Settlement Statement for the first day in month ‘x.’ Any deviation in filing actual cost data in accordance with this calendar must be requested of ERCOT, by the QSE representing an RMR Unit. Such request for deviation shall contain the reason for the inability to meet the calendar and an expected date that the cost data will be provided to ERCOT. At its discretion ERCOT may choose to honor such a request. No later than two Business Days following its decision, ERCOT shall issue a Market Notice of any such request and its response thereto. In the event that actual cost data is not submitted in accordance with the timeline or is not an approved deviation for the true-up, then the cost for the portion of Eligible Cost that has not been submitted is deemed to be zero.

(2) Actual fuel costs must be appropriate actual costs attributable to ERCOT’s scheduling and/or deployment of the RMR Unit. Actual fuel costs may include cost of fuel (including the cost of exceeding swing gas contract limits, additional gas demand costs set by fuel supply, or transportation contracts); demand fees, imbalance penalties, transportation charges, and cash out premiums. In addition, actual fuel costs may include costs incurred to:

(a) Keep the boiler(s) warmed, if approved in advance by ERCOT; and

(b) Test the RMR Unit prior to or during the term of the RMR Agreement, if approved in advance by ERCOT.

3.14.2 Black Start

(1) Each Generation Resource providing BSS must meet the requirements specified in North American Electric Reliability Corporation (NERC) Reliability Standards and the Operating Guides.

(2) Each Generation Resource providing BSS must meet the technical requirements specified in Section 8.1.1, QSE Ancillary Service Performance Standards, and Section 8.1.1.1, Ancillary Service Qualification and Testing.

(3) Bids for BSS are due on or before February 15th of each three-year period. Bids must be evaluated based on evaluation criteria attached as an appendix to the request for bids and contracted by December 31st for the following three-year period. ERCOT shall ensure BSSs are arranged, provided, and deployed as necessary to reenergize the ERCOT System following a Blackout or Partial Blackout.

(a) Resources shall disclose any weather-related limitations that could affect the Resource’s ability to provide BSS using the form provided in Section 22, Attachment M, Generation Resource Disclosure Regarding Bids for Black Start Service, as part of a bid to provide BSS.

(b) BSS bids shall include the hourly stand-by price and the BSS Back-up Fuel costs where applicable.

(c) When a Resource is selected to provide BSS, the Black Start Resource shall be required to complete all applicable testing requirements as specified in Section 8.1.1.2.1.5, System Black Start Capability Qualification and Testing.

(d) ERCOT shall provide a list of all prospective Black Start Resources that responded to the RFP for BSS to the impacted TSPs no later than seven days after the date on which bids for BSS are due. Any feedback from affected TSPs shall be limited to the identification of transmission constraints that may adversely impact the ability of the Black Start Resource to energize the “Next Start Resource” and shall be due to ERCOT by March 1st of that year. ERCOT shall share the feedback with the QSE representing the prospective Black Start Resource as soon as practicable. The QSE representing the Black Start Resource shall have the option to provide a response to any feedback provided by an affected TSP.

(4) ERCOT may schedule unannounced Black Start testing, to verify that BSS is operable as specified in Section 8.1.1.2.1.5.

(5) QSEs representing Generation Resources contracting for BSSs shall participate in training and restoration drills coordinated by ERCOT.

(6) ERCOT shall periodically determine and review the location and number of Black Start Resources required, as well as any special transmission or voice communication needs required. ERCOT and providers of this service shall meet the requirements as specified in the Operating Guides and in NERC Reliability Standards.

(7) A Resource Entity representing a Black Start Resource may request that an alternate Generation Resource which is connected to the same black start primary and secondary cranking path as the original Black Start Resource be substituted in place of the original Black Start Resource during the three-year term of an executed Standard Form Black Start Agreement (Section 22, Attachment D, Standard Form Black Start Agreement) if the alternate Generation Resource meets testing and verification under established qualification criteria to ensure BSS.

(a) ERCOT, in its sole discretion, may reject a Resource Entity’s request for an alternate Generation Resource and will provide the Resource Entity an explanation of such rejection.

(b) If ERCOT accepts the alternative Generation Resource as the substituted Black Start Resource, such acceptance shall not affect the original terms, conditions and obligations of the Resource Entity under the Standard Form Black Start Agreement. The Resource Entity shall submit to ERCOT an Amendment to Standard Form Black Start Agreement (Section 22, Attachment I, Amendment to Standard Form Black Start Agreement) after qualification criteria has been met.

(8) For the purpose of the Black Start Hourly Standby Fee as described in Section 6.6.8.1, Black Start Hourly Standby Fee Payment, the BSS Availability Reduction Factor shall be determined by using the availability for the original Black Start Resource and any substituted Black Start Resource(s), as appropriate for the rolling 4380-hour period of the evaluation.

(9) Each Generation Resource selected to provide BSS shall be prepared and able to provide BSS at any time as may be required by ERCOT, subject only to the limitations described in ERCOT Protocols or the Black Start Agreement.

(10) Each Generation Resource selected to provide BSS shall be able to utilize BSS Back-up Fuel for BSS and shall maintain a contracted amount of BSS Back-up Fuel to run the Black Start Resource for a minimum of 72 hours at its maximum output. The Generation Resource shall maintain the contracted amount of BSS Back-up Fuel at all times during the duration of the BSS contract term unless performing a BSS Back-up Fuel Switching Test or the Generation Resource is operating pursuant to a Black Start deployment event. This requirement does not apply to Resources that do not rely on purchased fuel.

(11) A Black Start Resource may utilize the contracted amount of BSS Back-up Fuel outside of BSS if ERCOT determines it is necessary during an Energy Emergency Alert (EEA) event.

(12) A Black Start Resource is not obligated to contract its full on site fuel storage capability for BSS Back-up Fuel. On site backup fuel in excess of the contracted BSS Back-up Fuel amount may be used by the Generation Resource at the discretion of the Generation Resource and ERCOT shall not prevent the Black Start Resource from utilizing the excess fuel, nor shall the Black Start Resource be required to request permission from ERCOT to utilize fuel in excess of the contracted BSS Back-up Fuel amount.

(13) ERCOT may, at its discretion, waive the BSS Back-up Fuel requirement stated in this Section, in whole or in part, if ERCOT deems necessary in order to procure a sufficient number or preferred combination of Generation Resources to provide BSS.

(14) A Resource Entity that submits a bid or is contracted to provide BSS or serve as an alternate to provide BSS with a Switchable Generation Resource (SWGR):

(a) Shall not nominate the SWGR to satisfy supply adequacy or capacity planning requirements in any Control Area other than the ERCOT Region during the term of the BSS contract;

(b) Shall submit a report to ERCOT in compliance with paragraph (2) of Section 16.5.4, Maintaining and Updating Resource Entity Information, indicating that the SWGR does not have any contractual requirement in a non-ERCOT Control Area during the term of the BSS contract; and

(c) Shall take any further action requested by ERCOT to ensure that ERCOT will be classified as the “Primary Party” for the SWGR under any agreement between ERCOT and another Control Area Operator (CAO) during the term of the BSS contract.

(15) If a Resource Entity with a SWGR is contracted to provide BSS or designated as an alternate to provide BSS, the Resource Entity shall have its Black Start plan procedures approved by ERCOT. In the event of a Partial Blackout or Blackout of the ERCOT System, the Resource Entity with a SWGR shall immediately:

(a) Effectuate its Black Start plan procedures to be available to provide BSS; and

(b) Provide BSS as directed by ERCOT or the local Transmission Operator (TO).

(16) Each Resource Entity shall identify in its Resources Registration data if its Resource is a Black Start Capable Resource and an Isochronous Control Capable Resource.

(17) Each Resource Entity and each TSP shall identify in the Network Operations Model if a modeled breaker or switch it operates or directs the operation of has a Synchroscope and a Synchronism Check Relay associated with the breaker or switch.

***3.14.3 Emergency Response Service***

(1) ERCOT shall procure and deploy ERS with the goal of promoting reliability prior to and during energy emergencies***.***

**3.14.3.1 Emergency Response Service Procurement**

(1) ERCOT shall issue Requests for Proposals to procure ERS for each Standard Contract Term. The ERS Standard Contract Terms are as follows:

(a) December through March;

(b) April and May;

(c) June through September; and

(d) October and November.

(2) ERCOT shall procure ERS from one or more of the four following ERS service types:

(a) Weather-Sensitive ERS-10

(b) Non-Weather-Sensitive ERS-10

(c) Weather-Sensitive ERS-30

(d) Non-Weather-Sensitive ERS-30

(3) ERS offers shall be submitted only by QSEs capable of receiving Extensible Markup Language (XML) messaging on behalf of represented ERS Resources.

(4) Each site in an ERS Generator must have an interconnection agreement with its TDSP prior to submitting an ERS offer and must have exported energy to the ERCOT System prior to the offer due date. An ERS Resource that cannot inject energy to the ERCOT System can only be offered as an ERS Load.

(5) In order to qualify as weather-sensitive, an ERS Load must meet one of the following criteria:

(a) The ERS Load must consist exclusively of residential sites; or

(b) The ERS Load must consist exclusively of non-residential sites and must qualify as weather-sensitive based on the accuracy of the regression baseline evaluation methodology as described in Section 8.1.3.1.1, Baselines for Emergency Response Service Loads, as an indicator of actual interval Load.

(i) ERCOT shall establish minimum accuracy standards for qualification as an ERS Load under the regression baseline evaluation methodology.

(ii) An ERS Load must have at least nine months of interval meter data to qualify as weather-sensitive under the regression baseline evaluation methodology.

(iii) ERCOT’s determination that an ERS Load qualifies as a weather-sensitive ERS Load is independent of ERCOT’s determination of which baseline methodologies may be appropriate for purposes of evaluating the ERS Load’s performance.

(c) If a site with Distributed Renewable Generation (DRG) has been designated by the QSE to be evaluated by using its native load, the default baseline analysis shall be performed using the calculated native load.

(6) QSEs representing ERS Resources may submit offers for one or more ERS Time Periods within an ERS Standard Contract Term. ERS Time Periods shall be defined by ERCOT in the RFP for that ERS Standard Contract Term. An ERS offer is specific to an ERS Time Period. In submitting an offer, both the QSE and the ERS Resource are committing to provide ERS for that ERS Time Period if selected.

(7) A QSE may submit separate offers for an ERS Resource to provide any or all of the four ERS service types during the same or different ERS Time Periods in the same ERS Standard Contract Term, but ERCOT shall only award offers for one service type for each ERS Resource.

(8) The minimum capacity offer for an ERS Load on the weather-sensitive baseline is one half (0.5) MW; all other ERS capacity offers will have a minimum amount that may be offered of one-tenth (0.1) MW. ERS Resources may be aggregated to reach this requirement.

(9) Offers from ERS Generators must include self-serve capacity and injection capacity amounts greater than or equal to zero for each ERS Time Period offered.

(10) ERCOT may establish an upper limit, in MWs, on the amount of ERS capacity it will procure for any ERS Time Period in any ERS Standard Contract Term.

(11) A QSE’s offer to provide ERS shall include:

(a) The name of the QSE representing the ERS Resource and the name of an individual authorized by the QSE to represent the QSE and its ERS Resource(s);

(b) The name of an Entity that controls the ERS Resource, and an affirmation that the QSE has obtained written authorization from the Entity to submit ERS offers on its behalf and to represent the Entity in all matters before ERCOT concerning the Entity’s provision of ERS;

(c) Any information or data specified by ERCOT, including access to historical meter data, and affirmation by the QSE that it has obtained written authorization from the controlling Entity of the ERS Resource for the QSE to obtain such data;

(d) Affirmation that the controlling Entity of the ERS Resource has reviewed P.U.C. Subst. R. 25.507, Electric Reliability Council of Texas (ERCOT) Emergency Response Service (ERS), these Protocols and Other Binding Documents relating to the provision of ERS, and has agreed to comply with and be bound by such provisions;

(e) An agreement by the QSE to produce any written authorization or agreement between the QSE and any ERS Resource it represents, as described in this Section, upon request from ERCOT or the PUCT;

(f) Affirmation that no offered capacity from any site in an ERS Resource has been or will be committed to provide any other product, service, or program during any of the hours in the ERS Time Period in the Standard Contract Term for which the offer is submitted.  Such prohibited products, services, or programs include, but are not limited to, Ancillary Services, Security-Constrained Economic Dispatch (SCED), or TDSP standard offer programs. As an exception to the foregoing, a QSE may offer a site to provide ERS for an ERS Time Period in the Standard Contract Term even if the QSE has an offer pending for that same site to serve as an MRA during that ERS Time Period and Standard Contract Term; however, if the site is selected to serve as an MRA it will not be permitted to serve as ERS during any ERS Time Period in the ERS Contract Term in which it is obligated to serve as an MRA;

(g) Affirmation that the QSE and the controlling Entity the ERS Resource are familiar with any applicable federal, state or local environmental regulations that apply to the use of any generator in the provision of ERS, and that the use of such generator(s) to provide of ERS would not violate those regulations. This provision applies to both ERS Generators and to the use of backup generation by ERS Loads; and

(h) Affirmation that each offered ERS Resource satisfies at least one of the conditions set forth in paragraph (9) of Section 3.6.1, Load Resource Participation, and that all of the ERS Resource’s offered Demand response capacity will be available if deployed by ERCOT during an emergency.

(12) Upon request from a QSE, ERCOT shall provide the dates and times for any deployment events or tests of any ERS site during the previous three ERS Standard Contract Terms, provided that the QSE has obtained written authorization from the ERS site to obtain the information from ERCOT. Such QSE requests shall include the following site-specific information: Electric Service Identifier (ESI ID), unique meter identifier (if applicable), or, if the site is in a Non-Opt-In Entity (NOIE) area, site name and site address.

(13) Sites associated with a Dynamically Scheduled Resource (DSR) may not participate in ERS. Offers for Resources containing sites associated with a DSR will be rejected by ERCOT. If ERCOT determines that any participating site is associated with a DSR, that site will be treated as removed from the Resource on the date the determination was made. An ERS Resource’s obligation will not change as a result of any such site removal.

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| ***[NPRR1000: Delete item (13) above upon system implementation and renumber accordingly.]*** |

(14) Each offer submitted by a QSE on behalf of an aggregated ERS Load on a weather-sensitive baseline shall include the QSE’s projection of the maximum number of sites in the aggregation during the ERS Standard Contract Term. ERCOT shall review this projection and the information provided regarding the initial size of each aggregated ERS Load and shall reject any offer on behalf of such an ERS Load if the maximum size of the ERS Load projected by the QSE would violate the limits of site participation growth described in paragraph (15) below.

(15) A QSE may modify the population of an aggregated ERS Load on a weather-sensitive baseline once per month during an ERS Standard Contract Term via a process defined by ERCOT. Such adjustments shall be effective on the first day of each month following the first month. A fully validated ERS Offer form must be received by ERCOT no later than seven Business Days prior to the first day of the month for which is intended to be in effect.

(a) During an ERS Standard Contract Term, a QSE may increase the number of sites in an aggregated ERS Load on a weather-sensitive baseline by no more than the greater of the following:

(i) 100% of the initial number of sites; or

(ii) Two MW times the QSE’s projection of the maximum number of sites in the aggregation during the ERS Standard Contract Term, divided by the maximum MW capacity offered for any ERS Time Period for the aggregation.

(b) Any sites added to an ERS Load on a weather-sensitive baseline are subject to the same requirements for historical meter data as the other sites in the aggregation, as described in paragraph (4) of Section 8.1.3.1.1.

(16) For each of the four ERS service types, an ERS Standard Contract Term may consist of a single ERS Contract Period or multiple non-overlapping ERS Contract Periods, as follows:

(a) If no ERS Resources’ obligations are exhausted for an ERS service type during an ERS Contract Period pursuant to Section 3.14.3.3, Emergency Response Service Provision and Technical Requirements, the ERS Contract Period for that ERS service type shall terminate at the end of the last Operating Day of the ERS Standard Contract Term.

(b) If one or more ERS Resources’ obligations in a given ERS service type are exhausted pursuant to Section 3.14.3.3, the ERS Contract Period for that ERS service type shall terminate at the end of the Operating Day during which the exhaustion occurred. However, if ERS Resources participating in a service type remain deployed at the end of that Operating Day, the ERS Contract Period for that ERS service type shall terminate at the end of the Operating Day on which those ERS Resources are recalled.

(c) If an ERS Contract Period terminates as provided in paragraph (b) above, and one or more ERS Resources’ obligations were not exhausted, a new ERS Contract Period for the ERS service type shall begin at hour ending 0100 on the following Operating Day. This new ERS Contract Period shall terminate as provided in this Section.

(d) If ERCOT elects pursuant to paragraph (b) above to renew the obligations of any ERS Resources whose obligations were entirely exhausted, a new ERS Contract Period for the ERS service type shall begin at hour ending 0100 on the Operating Day after ERCOT has notified QSEs that it has elected to renew the obligation. If a new ERS Contract Period was initiated pursuant to paragraph (c) above on an Operating Day prior to ERCOT issuing a notice of renewal under this paragraph, that ERS Contract Period shall terminate at the end of the Operating Day on which ERCOT notified QSEs that the renewal will take place. This new ERS Contract Period shall terminate as provided in this Section.

(17) An ERS Resource currently obligated to provide an ERS service type during an ERS Time Period and ERS Contract Period may be offered to provide service as an MRA during that same ERS Time Period in the ERS Contract Period. If the ERS Resource is selected to provide service as an MRA during an ERS Time Period in the ERS Contract Period in which it is currently obligated to provide an ERS service type, the ERS Contract Period will be terminated for that ERS service type. The ERS Contract Period for that ERS service type shall terminate at the end of the Operating Day that is five days before the first Operating Day the ERS Resource is obligated to provide service under the MRA Agreement. However, if any ERS Resources participating in that ERS service type are currently deployed at the end of the Operating Day the ERS Contract Period is scheduled to terminate, then the ERS Resource’s ERS Contract Period for that ERS service type shall continue until the end of the Operating Day on which all of the ERS Resources participating in that ERS service type have been recalled, at which time the ERS Contract Period will terminate.

(18) ERS Resources shall be obligated in ERS Contract Periods as follows:

(a) Unless an ERS Contract Period is terminated pursuant to paragraph (17) above, for the first ERS Contract Period in an ERS Standard Contract Term, all ERS Resources awarded by ERCOT shall be obligated.

(b) ERS Resources shall be obligated for 24 hours of cumulative deployment time for any ERS Contract Period during the December through March ERS Standard Contract Term. The obligated cumulative deployment time for any ERS Contract Period during all other ERS Standard Contract Terms shall be 12 hours.

(c) 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 the maximum deployment hours specified for the ERS Standard Contract Term in paragraph (b) above at the end of the last ERS Contract Period shall be obligated for only this remaining deployment time in the new ERS Contract Period.

(d) 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 and/or a specified MW quantity in which obligations have been exhausted.

(iii) If ERCOT decides to include renewal opt-ins in a subsequent ERS Contract Period, ERCOT shall promptly notify all ERS QSEs as to the ERS Time Periods and/or any specified MW quantity 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 December 1st and ending on November 30th, ERCOT shall not commit dollars toward ERS in excess of the ERS cost cap, except for the purpose of renewing ERS Resource obligations during a period where ERS has been exhausted. 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.

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| ***[NPRR1276: Replace paragraph (22) above with the following upon system implementation:]***  (22) ERCOT shall procure ERS Resources for each ERS Time Period using a clearing price. Section 22, Attachment Q, Emergency Response Service Procurement Methodology, 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 Section 22, Attachment Q, 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 the maximum cumulative deployment obligation time for an ERS Contract Period as specified in paragraph (18)(b) of Section 3.14.3.1, Emergency Response Service Procurement, 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)(c) of Section 3.14.3.1. Weather-Sensitive ERS test deployments do not contribute to the calculation of cumulative deployment obligation time.

(3) 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.

(4) 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 QSE must also ensure that interval metering is installed that measures the output of each site in the ERS Generator and that conforms with the requirements described in P.U.C. Subst. R. 25.142, Submetering for Apartments, Condominiums, and Mobile Home Parks. Time stamps shall conform to the requirements in Section 10.9.2, TSP or DSP Metered Entities. 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.

(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.

(5) 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.

(6) 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 year 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 ERCOT website 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;

(n) ERS QSE-level Payment Details Report; and

(o) ERS Obligation Report for TDSPs.

(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 post the information below to the MIS Certified Area for each affected TDSP:

(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 or unique meter identifier associated with each ERS Resource;

(e) Estimate of the ERS MW obligation by station code for TDSPs in competitive areas;

(f) Estimate of the ERS MW obligation by zip code for TDSPs in NOIE areas; and

(g) 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 ERCOT website 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.

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| ***[NPRR885, NPRR995, NPRR1007, and NPRR1246: Insert applicable portions of Sections 3.14.4 and 3.14.4.1 below upon system implementation for NPRR885 or NPRR995; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007 and NPRR1246:]***  3.14.4 Must-Run Alternative Service  **3.14.4.1 Overview and Description of MRAs**  (1) Subject to approval by the ERCOT Board, ERCOT may procure Must-Run Alternative (MRA) Service as an alternative to contracting with an RMR Unit if ERCOT determines that the MRA Agreement(s) will, in whole or in part, address the reliability need identified in the RMR study in a more cost-effective manner.  (2) ERCOT will issue a request for proposal (RFP) to solicit offers from QSEs to provide MRA Service.  (a) A QSE may submit an offer in response to the RFP or enter into an MRA Agreement only if it meets all registration and qualification criteria in Section 16.2, Registration and Qualification of Qualified Scheduling Entities.  (b) QSEs whose offers for MRA Service are accepted will be paid according to their offers, subject to the terms of the RFP, MRA Agreement and ERCOT Protocols. A clearing price mechanism shall not be used for awarding offers for MRA Service.  (c) A QSE may submit more than one offer for MRA Service in response to a single RFP. A QSE may not submit the same MRA or MRA Sites in more than one of its offers. ERCOT may award multiple offers to a QSE, so long as the MRA or MRA Sites in an awarded offer are not included in any other awarded offer. A QSE may condition ERCOT’s acceptance of an offer for a Demand Response MRA on ERCOT’s acceptance of an offer for a co-located Other Generation MRA offer.  (d) Demand Response MRAs and Other Generation MRAs, including MRA Sites within aggregated MRAs, that are situated in NOIE service territories, are eligible to provide MRA Service. Any QSE other than the NOIE QSE wishing to represent such MRAs must obtain written authorization allowing the representation from the NOIE in which the MRA is located. This authorization must be signed by an individual with authority to bind the NOIE and must be submitted to ERCOT prior to the submission of an offer in response to the MRA.  (3) An MRA may be connected at either transmission or distribution voltage.  (4) An MRA offer is ineligible to the extent it offers capacity that was included as a Resource in ERCOT’s RMR analysis or in the Load forecasts from the Steady State Working Group (SSWG) base cases used as the basis for the RMR analysis, as provided for in paragraph (3)(a) of Section 3.14.1.2, ERCOT Evaluation Process.  (5) Each MRA must provide at least five MW of capacity.  (6) Eligible MRA resources may include:  (a) A proposed Generation Resource or ESR that was not included in the reliability need evaluation pursuant to paragraph (3)(a) of Section 3.14.1.2.  (i) Proposed Generation Resources or ESRs must adhere to all interconnection requirements, including the requirements of Planning Guide Section 5, Generator Interconnection or Modification.  (ii) If the proposed Generation Resource is an Intermittent Renewable Resource (IRR), the QSE shall provide capacity values based on the Resource’s projected peak average capacity contribution during the MRA Contracted Hours.  (b) Proposed capacity additions to existing Generation Resources or ESRs, if the additional capacity was not included in the reliability need evaluation pursuant to paragraph (3)(a) of Section 3.14.1.2.  (i) Prior to providing MRA Service, the Resource Entity will be required to modify its Resource Registration information and complete necessary interconnection requirements with respect to this additional capacity.  (ii) If the capacity is being added to an IRR, the QSE shall provide capacity values based on the Resource’s projected peak average capacity contribution during the hours identified during the MRA Contracted Hours.  (c) A proposed or existing generator registered, or proposed to be registered, with ERCOT as a Settlement Only Generator (SOG) or as Distributed Generation (DG). If the generator is an intermittent renewable generator, the QSE, when responding to an RFP for MRA Service, shall provide capacity values based on the MRA’s projected peak average capacity contribution during the hours identified in the MRA Contracted Hours.  (d) Proposed or existing Demand response assets, which may include Load Resources and ERS Loads.  (e) A proposed or existing Energy Storage System (ESS) registered, or proposed to be registered, with ERCOT as a Settlement Only Energy Storage System (SOESS).  (7) An MRA must be able to provide power injection or Demand response to the ERCOT System at ERCOT’s discretion during the MRA Contracted Hours.  (a) QSE offers in response to an RFP for MRA Service must fully describe all of the MRA’s temporal constraints.  (b) For a Demand Response MRA, QSE offers in response to an RFP for MRA Service must include a statement as to whether the offered capacity is a Weather–Sensitive MRA.  (8) The QSE representing an MRA must be capable of receiving both VDI and XML instructions.  (9) ERCOT will periodically validate an MRA’s telemetry using 15-minute interval meter data.  (10) An MRA for which the MRA or every MRA Site, is metered with either an Advanced Meter or an ERCOT-Polled Settlement (EPS) Meter must be available for qualification testing no later than 10 days prior to the first day of the contracted MRA Service.  Other MRAs must be available for qualification testing no later than 45 days prior to the first day of the contracted MRA Service.  (11) All MRA Sites within an MRA must be of the same type (i.e., all Generation Resource MRA, ESR MRA, Other Generation MRA, or Demand Response MRA).  (12) A QSE representing an MRA shall submit to ERCOT and continuously update an Availability Plan for each MRA Contracted Hour for the current Operating Day and the next six Operating Days.  (13) A QSE representing an MRA or MRA Site may not submit DAM Offers, provide an Ancillary Service or carry an ERS responsibility on behalf of any MRA or MRA Site during the MRA Contracted Hours. Demand Response MRAs may not participate in TDSP standard offer programs during any MRA Contracted Hours.  (14) A Combined Cycle Train serving as an MRA must be configured as a single Combined Cycle Generation Resource.  (15) QSEs representing MRAs shall submit offers using an MRA offer sheet as provided by ERCOT.  (16) QSEs must submit the following information for each MRA offer:  (a) The capacity, months and hours offered;  (b) For an aggregated MRA, the offered capacity allocated to each MRA Site for all months and hours offered;  (c) The Resource ID, ESI ID and or unique meter ID associated with the MRA, or in the case of an aggregated MRA, a list of the Resource IDs, ESI IDs and/or unique meter IDs of the offered MRA Sites;  (d) The MRA Standby Price, represented in dollars per MW per hour;  (e) Required capital expenditure, if any, if the MRA offer is awarded;  (f) The MRA Event Deployment Price, in dollars per deployment event, or proxy fuel consumption rate;  (g) The ramp period or startup time of the MRA or aggregated MRA;  (h) The MRA Variable Price, in dollars per MW per hour, and/or proxy heat rate;  (i) The target availability of the MRA or aggregated MRA; and  (j) Any additional information required by ERCOT within the RFP.  (17) Demand Response MRAs shall not be deployed more than once per Operating Day.  (18) Except for a Forced Outage, any Outage of an MRA must be approved by ERCOT.  (19) For any MRA that is registered with ERCOT as a Resource, the QSE representing the MRA must be the same as the QSE representing the Resource. |

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| ***[NPRR885: Insert Section 3.14.4.2 below upon system implementation:]***  **3.14.4.2 Preliminary Review of Prospective Demand Response MRAs**  (1) In order to assist QSEs prior to their submission of MRA offers, ERCOT may provide QSEs, upon request, with an analysis of their prospective Demand Response MRA’s consumption patterns.  (2) ERCOT will provide a QSE with the analysis described under this Section only when the QSE makes its request in conformance with submission requirements and deadline set forth in the relevant MRA RFP.  (3) In response to a proper and timely request by a QSE, ERCOT will provide the following information for each prospective Demand Response MRA:  (a) Substation identification for each MRA or MRA Site;  (b) Demand Response MRA baseline options, if the resource qualifies for a default baseline; and  (c) Historical reference Load levels; and  (d) Any known errors or exceptions, such as whether the MRA or any MRA Sites are currently suspended from participation in another service (e.g., ERS), whether any listed MRA or MRA Sites have erroneous ESI IDs, or whether any prospective MRA or MRA Site lacks sufficient historical meter data.  (4) A submission by a QSE of a prospective Demand Response MRA does not bind the QSE to submit an offer for MRA Service. |

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| ***[NPRR885: Insert Section 3.14.4.3 below upon system implementation:]***  **3.14.4.3 MRA Substitution**  (1) Subject to approval by ERCOT, a QSE may provide a substitution for a contracted MRA. Any substituted MRA is subject to the same obligations as the originally awarded MRA.  (2) ERCOT, at its discretion, may disallow an MRA substitution if it determines that the substitution may cause operational or reliability concerns, does not provide expected reliability benefits equivalent to those under the MRA Agreement, or is inconsistent with Protocols.  (3) Any substitution must cover all MRA Contracted Hours in an Operating Day and may cover one or more Operating Days.  (4) For purposes of payment, for any calendar day during which one or more MRA substitutions was made, the performance of an MRA shall be determined based on the combined performance of the original and substitution MRAs. |

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| ***[NPRR885: Insert Section 3.14.4.4 below upon system implementation:]***  **3.14.4.4 Commitment and Dispatch**  (1) ERCOT may commit and/or Dispatch an MRA during the term of the MRA Agreement for the purpose of utilizing the MRA’s contracted capacity at any time during the contracted hours in the MRA Agreement.  (2) ERCOT may commit an MRA, via VDI, prior to the contracted hours in the MRA Agreement based on the MRA’s ramp period or startup time, in order to ensure that the MRA Service is provided during the contracted hours.  (3) In an MRA deployment event or unannounced test, the start time of the Demand response Ramp Period and/or generator startup time will be determined by ERCOT upon review of the time-stamped recording of the VDI. The start time begins when the ERCOT operator confirms the QSE’s repeat-back of the instruction. |

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| ***[NPRR885 and NPRR1246: Insert applicable portions of Section 3.14.4.5 below upon system implementation for NPRR885; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1246:]***  **3.14.4.5 Standards for Generation Resource MRAs and ESR MRAs**  (1) A Generation Resource MRA and ESR MRA shall at all times communicate accurate Resource Status to ERCOT via telemetry as described in Section 6.4.6, Resource Status.  (2) A Generation Resource MRA and ESR MRA shall be committed by ERCOT VDI and Dispatched by SCED. |

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| ***[NPRR885: Insert Sections 3.14.4.6 and 3.14.4.6.1 below upon system implementation:]***  **3.14.4.6 Standards for Other Generation MRAs and Demand Response MRAs**  3.14.4.6.1 MRA Telemetry Requirements  (1) A QSE representing an Other Generation MRA shall at all times communicate an accurate status to ERCOT via telemetry at the MRA level and shall provide at least the following values:  (a) Status (e.g., ON, OUT, etc…);  (b) High Sustained Limit (HSL);  (c) LSL;  (d) Current output level in MW;  (e) Gross Reactive Power in MVAr; and  (f) Net Reactive Power in MVAr.  (2) A Demand Response MRA’s QSE shall at all times communicate accurate MRA status to ERCOT via telemetry and shall provide at least the following values:  (a) Net Power Consumption (NPC); and  (b) Low Power Consumption (LPC)  (3) Event performance for Other Generation MRAs that are not Dispatched by SCED shall be evaluated by ERCOT as described in Section 3.14.4.6.5, MRA Event Performance Measurement and Verification. |

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| ***[NPRR885: Insert Section 3.14.4.6.2 below upon system implementation:]***  ***3.14.4.6.2 Baseline Performance Evaluation Methodology for Demand Response MRAs***  (1) A Demand Response MRA must qualify for one or more options described in the document entitled “Default Baseline Methodology” posted on the ERCOT website. The baseline will be used to verify the Demand Response MRA’s performance as compared to its contracted capacity during an MRA deployment event. |

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| ***[NPRR885: Insert Section 3.14.4.6.3 below upon system implementation:]***  ***3.14.4.6.3 MRA Metering and Metering Data***  (1) Each Demand Response MRA, or each MRA Site within an aggregated Demand Response MRA, must have an ESI ID and dedicated 15-minute Interval Data Recorder (IDR) metering. A Demand Response MRA, or an MRA Site within an aggregated Demand Response MRA, that is located outside of a competitive service area may use a unique meter ID in lieu of an ESI ID.  (2) Each Other Generation MRA, or each MRA Site within an aggregated Other Generation MRA, must have an ESI ID and, if applicable, a Resource ID and dedicated 15-minute IDR metering. An Other Generation MRA, or an MRA Site within an aggregated Other Generation MRA, that is located outside of a competitive service area may use unique meter IDs in lieu of the ESI ID and Resource ID.  (3) For ESI IDs and Resource IDs situated in either NOIE or competitive choice areas of the ERCOT Region, meter data is stored in the ERCOT systems and will be accessed by ERCOT and used for all performance evaluations.  (4) A QSE representing an MRA or MRA Site in a NOIE service territory is responsible for arranging with the NOIE TDSP to provide ERCOT with interval meter data for the MRA or MRA Site in a format prescribed by ERCOT on a monthly basis within 35 days following the end of a calendar month.  (5) ERCOT shall use 15-minute interval meter data, adjusted for the deemed actual DLFs, for each Demand Response MRA and each Other Generation MRA for purposes of availability and event performance measurement.  (a) The interval meter data for an MRA or MRA Site located in a competitive choice area will be adjusted by the DLFs used for Settlement for that MRA or MRA Site.  (b) The interval meter data for an MRA or MRA Site associated with a Unique Meter ID in a NOIE area will be adjusted based on a NOIE DSP DLF study submitted to ERCOT pursuant to Section 13.3, Distribution Losses. If no such study has been submitted, the interval meter data will not be adjusted for distribution losses. |

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| ***[NPRR885: Insert Section 3.14.4.6.4 below upon system implementation:]***  ***3.14.4.6.4 MRA Availability Measurement and Verification***  (1) Demand Response MRA and Other Generation MRA availability will be evaluated on a monthly basis.  (2) Within 45 days after the end of each month that a Demand Response MRA or an Other Generation MRA is obligated to be available under the terms of an MRA Agreement, ERCOT shall provide each QSE representing that MRA with a report of the MRAs availability for that month.  (3) For a Demand Response MRA or an Other Generation MRA, ERCOT will treat the MRA as unavailable for any committed intervals for which the meter data is not in ERCOT systems, regardless of the reason.  (4) For a Demand Response MRA, ERCOT will consider the Demand Response MRA to have been available for any 15-minute interval in which the Demand Response MRA was contracted and for which the most current Availability Plan for the Demand Response MRA indicates that the Demand Response MRA is available and for which the effective actual MW Load was greater than 95% of the Demand Response MRA’s effective contracted capacity; otherwise, the Demand Response MRA will be considered unavailable for that 15-minute interval. For purposes of payment under Section 6.6.6.7, MRA Standby Payment, the Demand Response MRA’s Monthly Availability Factor will be the ratio of the number of 15-minute intervals the Demand Response MRA was available during the MRA Contracted Month divided by the total number of contracted 15-minute intervals in the MRA Contracted Month. For purposes of this paragraph, the following shall apply:  (a) The effective actual MW Load in an interval for an aggregated Demand Response MRA shall be the aggregated sum across all MRA Sites of the product of -1, the MRA Site Shift Factor, and the MRA Site metered MW;  (b) The effective actual MW Load in an interval for a Demand Response MRA that is not an aggregation shall be the product of -1, the MRA Shift Factor, and the metered MW value;  (c) The effective contracted capacity in an interval for an aggregated Demand Response MRA shall be the aggregated sum across all MRA Sites of the product of -1, the MRA Site Shift Factor, and the MRA Site’s portion of the contract capacity; and  (d) The effective contracted capacity in an interval for a Demand Response MRA that is not an aggregation shall be the product of -1, the MRA Shift Factor, and the contract capacity.  (5) For an Other Generation MRA, ERCOT will consider the Other Generation MRA to have been available for any 15-minute interval in which the Other Generation MRA was contracted and for which the most current Availability Plan for the Other Generation MRA indicates that the Other Generation MRA is available and for which the Other Generation MRA’s export to the ERCOT System was equal to zero; otherwise, the Other Generation MRA will be considered unavailable for that 15-minute interval. For purposes of payment under Section 6.6.6.7, the Other Generation MRA’s Monthly Availability Factor will be the ratio of the number of 15-minute intervals the Other Generation MRA was available during the MRA Contracted Month divided by the total number of contracted 15-minute intervals in the MRA Contracted Month.  (6) The following intervals will be excluded in ERCOT’s calculations of an MRA’s Monthly Availability Factor, for purposes of payment under Section 6.6.6.7:  (a) Any 15-minute interval in which an MRA was deployed during an MRA deployment event or an unannounced ERCOT test;  (b) Any 15-minute intervals on the day of an MRA deployment or an unannounced ERCOT test following the issuance of the ERCOT recall instruction applicable to that MRA; and  (c) Any 15-minute interval in which an MRA or MRA Site was disabled or unverifiable due to events on the TDSP side of the meter affecting the generation, delivery or measurement of electricity to the MRA or MRA Site. QSEs must obtain documentation from the TDSP regarding such events and must provide copies of such documentation to ERCOT for any interval to be excluded from the Monthly Availability Factor calculation. |

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| ***[NPRR885: Insert Section 3.14.4.6.5 below upon system implementation:]***  ***3.14.4.6.5 MRA Event Performance Measurement and Verification***  (1) This section applies to both Demand Response MRAs and Other Generation MRAs. For purposes of this section, the following definitions apply:  (a) “Ramp Period” is the period of time, as set out in the MRA Agreement, by which the MRA agrees to begin delivering its contracted capacity following the ERCOT deployment VDI.  (b) “MRA Deployment Period” is the window of time beginning with the end of the MRA’s Ramp Period or the beginning of the MRA Contracted Hours, whichever is later, and ending with ERCOT’s VDI to recall the MRA.  (2) No later than 45 days after an event in which one or more Demand Response MRA or Other Generation MRA were tested or deployed, ERCOT shall provide each QSE representing an MRA with a performance report containing the results of ERCOT’s evaluation of the event or test for each deployed or tested MRA. The Event Performance Reduction Factor (MRAEPRF) for each MRA shall be the time-weighted average of the MRA’s Interval Performance Factors (MRAIPF) which are calculated as set out in paragraph (3) below.  (3) ERCOT shall calculate the MRAIPF for intervals during an unannounced ERCOT test or an MRA deployment as follows:  MRAIPF *q, r, i*  = Max(Min(((Effective Base\_MW *i* – Effective Actual\_MW *i*) / (IntFrac *i*  \* Effective Contracted\_Capacity\_MW *i*)),1),0)  Where:  IntFrac *i*= (CEndT *i* – CBegT *i*) / 15  The above variables are defined as follows:   |  |  |  | | --- | --- | --- | | **Variable** | **Unit** | **Description** | | MRAEPRF *q, r, m* | None | *Must-Run Alternative Event Performance Reduction Factor per QSE for the month*—The Event Performance Reduction Factor of the MRA *r* represented by QSE *q*, for each hour of the month *m*. The event performance reduction factor shall be determined as the time-weighted average of the Interval Performance Factor (MRAIPF). | | MRAIPF *q, r, i* | None | *Must-Run Alternative Interval Performance Factor per QSE per Resource for the interval*— The interval performance factor of the MRA *r* represented by QSE *q*, for the Settlement Interval *i*. | | IntFrac *i* | None | Interval fraction for that MRA for each Settlement Interval *i* in an MRA deployment period. | | Effective Base\_MW*i* | MW | For an aggregated Demand Response MRA, the aggregated sum of the product of -1, the MRA Site Shift Factor, and the MRA Site baseline MW values estimated by ERCOT for all MRA Sites in the MRA for that interval. For a Demand Response MRA that is not an aggregation, the product of -1, the MRA Shift Factor, and the MRA baseline MW value estimated by ERCOT for that interval.  For an aggregated Other Generation MRA, the aggregated sum of the product of -1, the MRA Site Shift Factor, and the MRA Site MW injected to the ERCOT System for the Settlement Interval *i*. For an Other Generation MRA that is not an aggregation, the product of -1, the MRA Shift Factor, and the MW injected to the grid by the MRA for that interval. | | Effective Actual\_MW *i* | MW | For an aggregated Demand Response MRA, the aggregated sum of the product of -1, the MRA Site Shift Factor and the metered MW values for all MRA Sites in the MRA for the Settlement Interval *i*. For a Demand Response MRA that is not an aggregation, the product of -1, the MRA Shift Factor and the metered MW value for the Settlement Interval *i*.  For an Other Generation MRA, zero. | | Effective Contracted\_Capacity\_MW *i* | MW | For an aggregated MRA, the sum of the product of -1, the MRA Site Shift Factor and the MRA Site portion of the contracted capacity of the MRA for the Settlement Interval *i*. | | CBegT *i* | Minutes | If the MRA deployment period begins during that interval, the time in minutes and fractions of minutes from the beginning of that interval to the beginning of the MRA deployment period, otherwise it is zero. | | CEndT *i* | Minutes | If the MRA deployment period ends during that interval, the time in minutes and fractions of minutes from the beginning of that interval to the end of the MRA deployment period, otherwise it is 15. | | *i* | None | A 15-minute Settlement Interval. | | *q* | none | A QSE. | | *m* | None | The index for a given month within the MRA Contracted Hours. | | *r* | None | An MRA. |   (4) For each unannounced ERCOT test or MRA deployment of a Demand Response MRA or Other Generation MRA, ERCOT will calculate an MRA Event Performance Reduction Factor (MRAEPRF) as described in paragraph (2) above for the intervals covered by the test/event. The Event Performance Reduction Factor calculation will begin with the first partial or full interval in the MRA deployment period and will end with the last full interval in the MRA deployment period.  (5) A Demand Response MRA shall be deemed to have met its test/event performance requirements if it is determined by ERCOT to have met its Demand response obligations in the MRA deployment event as measured using the ERCOT-established baseline that ERCOT determines most accurately represents the Demand Response MRA’s Demand response contribution.  (6) The MRA deployment period for a Demand Response MRA or Other Generation MRA will end at the time ERCOT issues a release instruction via VDI, or the end of the last MRA Contracted Hour on the day of the deployment, whichever is earlier.  (7) Event Performance Reduction Factors are expressed as a number between 0 and 1, rounded to three decimal places.  (8) A Demand Response MRA or an Other Generation MRA that achieves an Event Performance Reduction Factor of 0.950 or greater for a test/event and an Interval Performance Factor for the first full interval of the test/event of 0.950 or greater will be deemed to have successfully met its deployment obligations for that test/event.  (9) If a Demand Response MRA or an Other Generation MRA fails to achieve an Event Performance Reduction Factor of 0.950 or greater, the Interval Performance Factors for that MRA for that event will be multiplied by an adjustment factor such that the Event Performance Reduction Factor for the test/event will be equal to the square of the original event performance factor.  (10) If a Demand Response MRA has been classified by ERCOT as providing Weather-Sensitive MRA, and if ERCOT determines that the normalized peak Demand reduction value for the Demand Response MRA is greater than 95% of the largest contracted capacity value offered in any MRA Contracted Hour by the QSE for the Demand Response MRA, ERCOT shall not apply the adjustment factors as specified in paragraph (9) above. To determine the normalized peak Demand reduction value, ERCOT shall:  (a) Calculate an average Demand reduction value across the intervals for each test and/or actual deployment event during the MRA contract period. For this purpose the Demand reduction value for an interval shall be calculated as the greater of zero or effective base MW for the interval less the effective actual MW for the interval; and  (b) Model the relationship of the average Demand reduction values determined in paragraph (a) above to actual weather and use the derived normalized peak Demand reduction value as the value that would be realized under normalized peak weather conditions.  (11) For any contracted month in which ERCOT has deployed one or more Demand Response MRAs or Other Generation MRAs more than once for either an unannounced test or an MRA deployment, the Event Performance Reduction Factor (MRAEPRF) as described in paragraph (2) above for the MRA for the contracted month shall be the time-weighted average of the interval performance factor values for all tests/events in the Contracted Month. The interval performance factors used for this calculation shall reflect any squaring applied pursuant to paragraph (9) above. |

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| ***[NPRR885: Insert Section 3.14.4.6.5.1 below upon system implementation:]***  **3.14.4.6.5.1 Event Performance Measurement and Verification for Co-Located Demand Response MRAs and Other Generation MRAs**  (1) A Demand Response MRA shall be deemed by ERCOT to be co-located with an Other Generation MRA when all of the following conditions are satisfied:  (a) For an aggregated Demand Response MRA and an aggregated Other Generation MRA, each MRA Site in the Demand Response MRA is physically located with an MRA Site in the Other Generation MRA;  (b) For a Demand Response MRA that is not an aggregation and an Other Generation MRA that is not an aggregation, the Demand Response MRA is physically located with the Other Generation MRA;  (c) For a Demand Response MRA that is not an aggregation and an aggregated Other Generation MRA, the Demand Response MRA is physically located with an MRA Site the Other Generation MRA;  (d) The MRA Contracted Hours for the Demand Response MRA are the same as the MRA Contracted Hours for the Other Generation MRA; and  (e) The Demand Response MRA has not been classified by ERCOT as providing Weather-Sensitive MRA.  (2) If a Demand Response MRA has been deemed by ERCOT to be co-located with an Other Generation MRA, the event performance of the two Resources shall be calculated as a combination. For the calculations described in paragraph (2) of Section 3.14.4.6.5, MRA Event Performance Measurement and Verification, the effective base MW of the combination shall be the sum of the values calculated for the Demand Response MRA and Other Generation MRA, the effective actual MW shall be the sum of the values calculated for the Demand Response MRA and Other Generation MRA, and the effective contract capacity MW shall be the sum of the values calculated for the Demand Response MRA and Other Generation MRA.  (3) For the calculations described in paragraph (3) of Section 3.14.4.6.5, the MRAEPRF for the co-located combination shall be calculated as the time-weighted average of the interval performance factors calculated for the combination of the Demand Response MRA and Other Generation MRA. The steps described in paragraphs (4) through (10) of Section 3.14.4.6.5 shall be followed for the combination of the Demand Response MRA and Other Generation MRA, and the MRAEPRF for the Demand Response MRA and Other Generation MRA for the MRA Contracted Month shall be equal to the MRAEPRF calculated for the combination for the MRA Contracted Month. |

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| ***[NPRR885 and NPRR1246: Insert applicable portions of Section 3.14.4.7 below upon system implementation for NPRR885; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1246:]***  **3.14.4.7 MRA Testing**  (1) ERCOT shall conduct a test of every MRA prior to the initial MRA Contracted Month.  (2) ERCOT may conduct an unannounced test of any MRA at any time during a MRA Contracted Month. Testing for MRAs, other than for Demand Response MRAs classified as providing Weather-Sensitive MRA, will be limited to no more than once per MRA Contracted Month. Testing for Demand Response MRAs classified as Weather-Sensitive MRA will be limited to no more than twice per MRA Contracted Month.  (3) ERCOT will not conduct an unannounced test of an MRA during a calendar month subsequent to an actual MRA deployment event.  (4) A substituted Demand Response MRA or Other Generation MRA will be subject to monthly unannounced testing regardless of tests or events occurring prior to the start date of the substitution.  (5) ERCOT shall limit the duration of MRA deployment periods of any single test to a maximum of one hour.  (6) For the purposes of Section 6.6.6.7, MRA Standby Payment, ERCOT may adjust the testing capacity results for a Generation Resource MRA or an ESR MRA to reflect conditions beyond the control of the Generation Resource MRA or ESR MRA. |

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| ***[NPRR885: Insert Section 3.14.4.8 below upon system implementation:]***  **3.14.4.8 MRA Misconduct Events**  (1) With respect to MRA Service, a “Misconduct Event” means any MRA Contracted Hour during which the MRA, in a deployment event, is directed to but does not make available to ERCOT the power injection or Demand response in the amount shown in the MRA Availability Plan.  (2) ERCOT will charge a QSE representing an MRA for unexcused Misconduct Events as specified in Section 6.6.6.11, MRA Charge for Unexcused Misconduct.  (3) ERCOT will assess a single charge to the QSE for each Operating Day on which one or more Misconduct Event occurs.  (4) The QSE may be excused by ERCOT from a Misconduct Event charge if ERCOT determines, in its discretion, that the Misconduct Event was not due to intentionally incomplete or inaccurate reporting to ERCOT regarding the availability of the MRA.  (5) ERCOT shall inform the QSE in writing of its determination if a Misconduct Event is deemed unexcused. |

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| ***[NPRR885: Insert Section 3.14.4.9 below upon system implementation:]***  **3.14.4.9 MRA Reporting to Transmission and/or Distribution Service Providers (TDSPs)**  (1) At least 24 hours before the beginning of an MRA Contracted Month, ERCOT shall provide the report described in paragraph (2) below to each TDSP that has a Demand Response MRA or Other Generation MRA within their service area that is providing MRA Service for the MRA Contracted Month.  (2) The report will include the following information for each MRA and MRA Site within the TDSP’s service area:  (a) The name of the QSE representing each MRA or MRA Site;  (b) A list of the Resource IDs, ESI IDs, and Unique Meter IDs for each MRA or MRA Site;  (c) The date of the interconnection agreement for each Resource ID; and  (d) For each Operating Hour, the aggregate contracted capacity for all MRAs and MRA Sites within the TDSP’s service area, by station code in competitive areas and by zip code in NOIE areas.  (3) Reports provided under this section are Protected Information under Section 1.3.1.1, Items Considered Protected Information. TDSPs shall maintain the confidentiality of the reports. |

***3.14.5 Firm Fuel Supply Service***

(1) Each Generation Resource providing or offering to provide Firm Fuel Supply Service (FFSS), including the primary and any alternate Generation Resources identified in the FFSS Offer Submission Form, 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.

(2) ERCOT shall issue an RFP by August 1 of each year soliciting offers from QSEs for Generation Resources to provide FFSS. The RFP shall require offers to be submitted on or before September 1of each year.

(3) QSEs may submit offers individually for one or more Generation Resources to provide FFSS using the FFSS Offer Submission Form posted on the ERCOT website. A QSE may not submit an offer for a given Generation Resource unless it is the QSE designated by the Resource Entity associated with that Generation Resource. ERCOT must evaluate offers using criteria identified in an appendix to the RFP. ERCOT will issue FFSS awards by September 30 and will post the awards to the MIS Certified Area for each QSE that is awarded an FFSS obligation. The posting will include information such as, but not limited to, the identity of the primary Generation Resource and any alternate Generation Resource(s), the FFSS clearing price, the amount of reserved fuel associated with the FFSS award, the MW amount awarded, and the Generation Resource’s initial minimum LSL when providing FFSS. The RFP awards shall cover a period beginning November 15 of the year in which the RFP is issued and ending on March 15 of the year after the year in which the RFP is issued. A QSE may submit an offer for one or more Generation Resources to provide FFSS beginning in the same year the RFP is issued or as otherwise specified in the RFP. An FFSS Resource (FFSSR) shall be considered an FFSSR and is required to provide FFSS from November 15 through March 15 for each year of the awarded FFSS obligation period. ERCOT shall ensure FFSSRs are procured and deployed as necessary to maintain ERCOT System reliability during, or in preparation for, a natural gas curtailment or other fuel supply disruption.

(a) On the FFSS Offer Submission Form, the QSE shall disclose information including, but not limited to, the Generation Resource and any alternate Generation Resource(s), the amount of reserved fuel offered, the MW available from the capacity offered, an estimate of the time to restock fuel reserves, and each limitation of the offered Generation Resource that could affect the Generation Resource’s ability to provide FFSS.

(b) If the QSE offers a Generation Resource as meeting the qualification requirements in paragraph (1)(c) of Section 8.1.1.2.1.6, Firm Fuel Supply Service Resource Qualification, Testing, Decertification, and Recertification, the QSE must submit as part of its offer a certification for the offered Generation Resource. The certification must include:

(i) Certification that the Generation Entity for the Generation Resource (or an Affiliate) has a Firm Transportation Agreement, firm natural gas supply, and contracted or owned storage capacity meeting the qualification requirements in paragraph (1)(c) of Section 8.1.1.2.1.6;

(ii) The following information regarding the Firm Transportation Agreement:

(A) FFSS Qualifying Pipeline name;

(B) Term;

(C) Primary points of receipt and delivery;

(D) Maximum daily contract quantity (in MMBtu);

(E) Shipper of record; and

(F) Whether the Firm Transportation Agreement provides for ratable receipts and deliveries; and

(iii) The following information regarding the storage arrangements:

(A) Storage facility name;

(B) Term of the Firm Gas Storage Agreement (if applicable);

(C) Maximum storage quantity owned or contracted under the Firm Gas Storage Agreement (in MMBtu); and

(D) Maximum daily withdrawal quantity (in MMBtu).

(c) For a Generation Resource to be eligible to receive an FFSS award, the primary Generation Resource and any alternate Generation Resource(s) identified in the FFSS Offer Submission Form shall complete all applicable testing requirements as specified in Section 8.1.1.2.1.6. A QSE representing an FFSSR is allowed to provide the FFSS with an alternate Resource previously approved by ERCOT to replace the FFSSR.

(d) An offer to provide FFSS is an offer to supply an awarded amount of capacity, maintain a sufficient amount of reserved fuel to meet that award for the duration requirement specified in the RFP, and to designate a specific number of emissions hours that will be reserved for the awarded FFSSR in meeting its obligation to perform in the event that FFSS is deployed. Reserved fuel, emissions hours, and other attributes, in excess of what is needed to meet the FFSS obligation can be used at the discretion of the QSE as long as sufficient fuel reserves and emissions hours are maintained for the purposes of ERCOT deployment of FFSS.

(e) Within ten Business Days of issuing FFSS awards, ERCOT will post on the ERCOT website the identity of all Generation Resources that were offered as primary Generation Resources or alternate Generation Resources to provide FFSS for the most recent procurement period, including prices and quantities offered.

(4) The QSE for an FFSSR shall ensure that the Resource is prepared and able to come On-Line or remain On-Line in order to maintain Resource availability in the event of a natural gas curtailment or other fuel supply disruption.

(a) When ERCOT issues a Watch for winter weather, ERCOT will notify all Market Participants, including all QSEs representing FFSSRs, to begin preparation for potential FFSS deployment. Such preparation may include, but is not limited to, circulation of alternate fuel to its facilities, if applicable; heat fuel oil to appropriate temperatures, if applicable; call out additional personnel as necessary, and be ready to receive a Dispatch Instruction to provide FFSS. An FFSSR may begin consuming a minimum amount of alternate fuel to validate it is ready for an FFSS deployment.

(b) In anticipation of or in the event of a natural gas curtailment or other fuel supply disruption to an FFSSR, the QSE shall notify ERCOT as soon as practicable and may request approval to deploy FFSS to generate electricity. ERCOT shall evaluate system conditions and may approve the QSE’s request. The QSE shall not deploy the FFSS unless approved by ERCOT. Upon approval to deploy FFSS, ERCOT shall issue an FFSS Verbal Dispatch Instruction (VDI) to the QSE. ERCOT may issue separate VDIs for each Operating Day for each FFSSR that is deployed for FFSS.

(c) In conjunction with a QSE notification under paragraph (b) above, the QSE shall also report to ERCOT any environmental limitations that would impair the ability of the FFSSR to provide FFSS for the required duration of the FFSS award.

(d) ERCOT may issue an FFSS VDI without a request from the QSE, however ERCOT shall not issue an FFSS VDI without evidence of an impending or actual fuel supply disruption affecting the FFSSR.

(e) If the FFSSR is generating at a level above the FFSS MW awarded amount and that level of output cannot be sustained for the required duration of the FFSS award, ERCOT may use a manual High Dispatch Limit (HDL) override to ensure the FFSSR can continue to generate at the FFSS MW award level for the entire FFSS duration requirement specified in the RFP.

(f) The FFSSR shall continuously deploy FFSS to generate electricity until the earlier of (i) the exhaustion of the fuel reserved to generate at the FFSS MW award level for the duration requirement specified in the RFP, including any fuel that was restocked following approval or instruction from ERCOT, (ii) the fuel supply disruption no longer exists, or (iii) ERCOT determines the FFSS deployment is no longer needed. Upon satisfying one of these qualifications, ERCOT shall terminate the VDI. In the event of (i), the FFSSR shall not be obligated to continue being available for FFSS deployment for the remainder of the Watch. In the event of (ii) or (iii), the FFSSR shall continue being available for FFSS deployment for the remainder of the Watch.

(g) The QSE for the FFSSR is responsible for communicating with the ERCOT control room the anticipated exhaustion of the reserved fuel at least six hours before that anticipated exhaustion and upon the exhaustion of that fuel.

(h) A QSE shall notify the ERCOT control room of the anticipated exhaustion of emissions credits or permit allowances at least six hours before the exhaustion of those credits or allowances. Upon receiving such notification, ERCOT shall modify the VDI so the FFSS deployment is terminated upon exhaustion of those credits or allowances.

(i) Upon deployment or recall of FFSS, ERCOT shall notify all Market Participants that such deployment or recall has been made, including the MW capacity of service deployed or recalled.

(5) Following each deployment of FFSS, the QSE for an FFSSR may request approval from ERCOT via email to [FFSS@ercot.com](mailto:FFSS@ercot.com), or ERCOT may instruct the QSE to restock their fuel reserve to restore their ability to generate at the FFSS MW award level for the duration requirement specified in the RFP as follows:

(a) The QSE requests preliminary approval from ERCOT control room, or ERCOT provides preliminary instruction, to restock and provide ERCOT an initial estimated timeline to complete the refueling.

(b) After receiving preliminary approval or instruction from ERCOT, the QSE shall:

(i) Immediately provide a final estimate for completing the restocking of fuel; or

(ii) Within 24 hours, notify the ERCOT control room with an updated estimated timeline to complete the restocking of the fuel.

(c) Based on the most recent expected time needed to restock the fuel, the ERCOT control room may or may not provide final approval for restocking of the fuel.

(d) If ERCOT makes final approval to restock the fuel, the QSE representing the FFSSR shall inform the ERCOT control room immediately when restocking is complete.

(6) Following final approval from ERCOT, a QSE must restock their fuel reserve, using existing fuel inventories or new fuel purchases, to restore their ability to generate at the FFSS MW award level for the specified duration requirement. In the event ERCOT does not receive the request to restock from a QSE representing an FFSSR, but the QSE no longer has sufficient reserved fuel to generate at the FFSS MW award level for the specified duration requirement, the QSE shall communicate to the ERCOT control room this reduced capability and ERCOT may instruct the QSE to restock the fuel reserve as described in paragraph (5) above.

(7) For a Resource to be considered as an alternate for providing FFSS, the following requirements must be met. The alternate Resource must:

(a) Be able to provide net real power sufficient to generate at the same FFSS MW award level as the primary Resource for the duration requirement specified in the RFP;

(b) Be a single Generation Resource, as registered with ERCOT; and

(c) Use the same source of fuel reserve for providing FFSS as the primary Resource.

(8) An FFSS Offer Submission Form may have up to three alternate Generation Resources per primary Resource offering to provide FFSS.

(9) For FFSSRs with approved alternate Generation Resources if the FFSSR becomes unavailable, the QSE must:

(a) As soon as practicable, notify ERCOT via email to [FFSS@ercot.com](mailto:FFSS@ercot.com) and inform ERCOT that the FFSSR will be replaced by one of the alternate Generation Resources, specify which alternate Generation Resource (if multiple alternate Generation Resources have been designated), and provide an estimate of how long the replacement will be in effect;

(b) Update the Availability Plans for these Generation Resources to reflect current operating conditions within 60 minutes after identifying the change in availability of the FFSSR; and

(c) Update the COPs for these Generation Resources within 60 minutes after identifying the change in availability of the FFSSR.

(10) For FFSSRs that were replaced by one of their approved alternate Generation Resources, when the primary Resource is once again the FFSSR, the QSE must notify ERCOT of the change via email to the email address provided in paragraph (9)(a) above as soon as practicable.

(11) An FFSSR providing BSS must have sufficient fuel reserved to generate at the FFSS MW award level for the duration requirement specified in the RFP in addition to any fuel required for the Generation Resource to meet the contracted BSS obligation. Any remaining fuel reserve in addition to that required for meeting FFSS and BSS obligations can be used at the QSE’s discretion.

(12) If ERCOT issues an FFSS VDI to an FFSSR for the same Operating Hour where a RUC instruction was issued, then for Settlement purposes ERCOT will consider the RUC instruction as cancelled.

(13) If FFSS is deployed, then ERCOT will provide a report to the TAC or its designated subcommittee within 45 days of the end of the FFSS obligation period. The report must include the Resources deployed and the reason for any deployments.

(14) Any QSE that submits an offer or receives an award for a SWGR to provide FFSS, and the Resource Entity that owns or controls that SWGR, shall:

(a) Not nominate the SWGR to satisfy supply adequacy or capacity planning requirements in any Control Area other than the ERCOT Region during the period of the FFSS obligation; and

(b) Take any further action requested by ERCOT to ensure that ERCOT will be classified as the “Primary Party” for the SWGR under any agreement between ERCOT and another CAO during the period of the FFSS obligation.

(15) On an annual basis after the FFSS season, ERCOT will provide a report separately for the total amounts from Section 6.6.14.1, Firm Fuel Supply Service Fuel Replacement Costs Recovery, and Section 6.6.14.2, Firm Fuel Supply Service Hourly Standby Fee Payment and Fuel Replacement Cost Recovery, to the TAC or its designated subcommittee.

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.

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| ***[NPRR1240: Replace paragraph (i) above with the following upon system implementation:]***  (1) ERCOT, in coordination with the Transmission Service Providers (TSPs), shall establish and update, as necessary, the ERCOT System Voltage Profile and shall post it on the ERCOT website. ERCOT, the interconnecting TSP, or that TSP’s agent, may modify the Voltage Set Point described in the Voltage Profile based on current system conditions. |

(2) All Generation Resources (including self-serve generating units) and Energy Storage Resources (ESRs) that are connected to Transmission Facilities and that have a gross unit rating greater than 20 MVA or those units connected at the same Point of Interconnection Bus (POIB) that have gross unit ratings aggregating to greater than 20 MVA, that supply power to the ERCOT Transmission Grid, shall provide Voltage Support Service (VSS).

(3) Except as reasonably necessary to ensure reliability or operational efficiency, TSPs should utilize available static reactive devices prior to requesting a Voltage Set Point change from a Generation Resource or ESR.

(4) Each Generation Resource and ESR required to provide VSS shall comply with the following Reactive Power requirements in Real-Time operations when issued a Voltage Set Point by a TSP or ERCOT:

(a) An over-excited (lagging or producing) power factor capability of 0.95 or less determined at the unit's maximum net power to be supplied to the ERCOT Transmission Grid and for any Voltage Set Point from 0.95 per unit to 1.04 per unit, as measured at the POIB;

(b) An under-excited (leading or absorbing) power factor capability of 0.95 or less, determined at the unit's maximum net power to be supplied to the ERCOT Transmission Grid and for any Voltage Set Point from 1.0 per unit to 1.05 per unit, as measured at the POIB;

(c) For any Voltage Set Point outside of the voltage ranges described in paragraphs (a) and (b) above, the Generation Resource or ESR shall supply or absorb the maximum amount of Reactive Power available within its inherent capability and the capability of any VAr-capable devices as necessary to achieve the Voltage Set Point;

(d) When a Generation Resource or an ESR required to provide VSS is issued a new Voltage Set Point, that Generation Resource or ESR shall make adjustments in response to the new Voltage Set Point, regardless of whether the current voltage is within the tolerances identified in paragraph (4) of Nodal Operating Guide Section 2.7.3.5, Resource Entity Responsibilities and Generation Resource and Energy Storage Resource Requirements;

(e) For Generation Resources, the Reactive Power capability shall be available at all MW output levels and may be met through a combination of the Generation Resource’s Corrected Unit Reactive Limit (CURL), which is the generating unit’s dynamic leading and lagging operating capability, and/or dynamic VAr-capable devices. This Reactive Power profile is depicted graphically as a rectangle. For Intermittent Renewable Resources (IRRs), the Reactive Power requirements shall be available at all MW output levels at or above 10% of the IRR’s nameplate capacity. When an IRR is operating below 10% of its nameplate capacity and is unable to support voltage at the POIB, ERCOT, the interconnecting TSP, or that TSP’s agent may require an IRR to disconnect from the ERCOT System for purposes of maintaining reliability. For ESRs, the Reactive Power capability shall be available at all MW levels, when charging or discharging, and may be met through a combination of the ESR’s CURL, and/or dynamic VAr-capable devices. For any ESR that achieved Initial Synchronization before December 16, 2019, the requirement to have Reactive Power capability when charging does not apply if the Resource Entity for the ESR has submitted a notarized attestation to ERCOT stating that, since the date of Initial Synchronization, the ESR has been unable to comply with this requirement without physical or software changes/modifications, and ERCOT has provided written confirmation of the exemption to the Resource Entity. The exemption shall apply only to the extent of the ESR’s inability to comply with the requirement when the ESR is charging;

(f) For any Generation Resource or ESR that is part of a Self-Limiting Facility, the capabilities described in paragraphs (a) and (b) above shall be determined based on the Self-Limiting Facility’s established MW Injection limit and, if applicable, established MW Withdrawal limit.

(5) As part of the technical Resource testing requirements prior to the Resource Commissioning Date, all Generation Resources and ESRs must conduct an engineering study, and demonstrate through performance testing, the ability to comply with the Reactive Power capability requirements in paragraph (4), (7), (8), or (9) of this Section, as applicable. Any study and testing results must be accepted by ERCOT prior to the Resource Commissioning Date.

(6) Except for a Generation Resource or an ESR subject to Planning Guide Section 5.2.1, Applicability, a Generation Resource or an ESR that has already been commissioned is not required to submit a new reactive study or conduct commissioning-related reactive testing, as described in paragraph (5) above.

(7) Wind-powered Generation Resources (WGRs) that commenced operation on or after February 17, 2004, and have a signed Standard Generation Interconnection Agreement (SGIA) on or before December 1, 2009 (“Existing Non-Exempt WGRs”), must be capable of producing a defined quantity of Reactive Power to maintain a set point in the Voltage Profile established by ERCOT in accordance with the Reactive Power requirements established in paragraph (4) above, except in the circumstances described in paragraph (a) below.

(a) Existing Non-Exempt WGRs whose current design does not allow them to meet the Reactive Power requirements established in paragraph (4) above must conduct an engineering study using the Summer/Fall 2010 on-peak/off-peak Voltage Profiles, or conduct performance testing to determine their actual Reactive Power capability. Any study or testing results must be accepted by ERCOT. The Reactive Power requirements applicable to these Existing Non-Exempt WGRs will be the greater of: the leading and lagging Reactive Power capabilities established by the Existing Non-Exempt WGR’s engineering study or testing results; or Reactive Power proportional to the real power output of the Existing Non-Exempt WGR (this Reactive Power profile is depicted graphically as a triangle) sufficient to provide an over-excited (lagging) power factor capability of 0.95 or less and an under-excited (leading) power factor capability of 0.95 or less, both determined at the WGR’s set point in the Voltage Profile established by ERCOT, and both measured at the POIB.

(i) Existing Non-Exempt WGRs shall submit the engineering study results or testing results to ERCOT no later than five Business Days after its completion.

(ii) Existing Non-Exempt WGRs shall update any and all Resource Registration data regarding their Reactive Power capability documented by the engineering study results or testing results.

(iii) If the Existing Non-Exempt WGR’s engineering study results or testing results indicate that the WGR is not able to provide Reactive Power capability that meets the triangle profile described in paragraph (a) above, then the Existing Non-Exempt WGR will take steps necessary to meet that Reactive Power requirement depicted graphically as a triangle by a date mutually agreed upon by the Existing Non-Exempt WGR and ERCOT. The Existing Non-Exempt WGR may meet the Reactive Power requirement through a combination of the WGR’s Unit Reactive Limit (URL) and/or automatically switchable static VAr-capable devices and/or dynamic VAr-capable devices. No later than five Business Days after completion of the steps to meet that Reactive Power requirement, the Existing Non-Exempt WGR will update any and all Resource Registration data regarding its Reactive Power and provide written notice to ERCOT that it has completed the steps necessary to meet its Reactive Power requirement.

(iv) For purposes of measuring future compliance with Reactive Power requirements for Existing Non-Exempt WGRs, results from performance testing or the Summer/Fall 2010 on-peak/off-peak Voltage Profiles utilized in the Existing Non-Exempt WGR’s engineering study shall be the basis for measuring compliance, even if the Voltage Profiles provided to the Existing Non-Exempt WGR are revised for other purposes.

(b) Existing Non-Exempt WGRs whose current design allows them to meet the Reactive Power requirements established in paragraph (4) above (depicted graphically as a rectangle) shall continue to comply with that requirement. ERCOT, with cause, may request that these Existing Non-Exempt WGRs provide further evidence, including an engineering study, or performance testing, to confirm accuracy of Resource Registration data supporting their Reactive Power capability.

(8) Qualified Renewable Generation Resources (as described in Section 14, State of Texas Renewable Energy Credit Trading Program) in operation before February 17, 2004, required to provide VSS and all other Generation Resources required to provide VSS that were in operation prior to September 1, 1999, whose current design does not allow them to meet the Reactive Power requirements established in paragraph (4) above, will be required to maintain a Reactive Power requirement as defined by the Generation Resource’s URL that was submitted to ERCOT and established per the criteria in the ERCOT Operating Guides.

(9) New generating units connected before May 17, 2005, whose owners demonstrate to ERCOT’s satisfaction that design and/or equipment procurement decisions were made prior to February 17, 2004, based upon previous standards, whose design does not allow them to meet the Reactive Power requirements established in paragraph (4) above, will be required to maintain a Reactive Power requirement as defined by the Generation Resource’s URL that was submitted to ERCOT and established per the criteria in the Operating Guides.

(10) For purposes of meeting the Reactive Power requirements in paragraphs (4) through (9) above, multiple units including IRRs shall, at a Resource Entity’s option, be treated as a single Resource if the units are connected to the same transmission bus.

(11) Resource Entities may submit to ERCOT specific proposals to meet the Reactive Power requirements established in paragraph (4) above by employing a combination of the CURL and added VAr capability, provided that the added VAr capability shall be automatically switchable static and/or dynamic VAr devices. A Resource Entity and TSP may enter into an agreement in which the proposed static VAr devices can be switchable using Supervisory Control and Data Acquisition (SCADA). ERCOT may, at its sole discretion, either approve or deny a specific proposal, provided that in either case, ERCOT shall provide the submitter an explanation of its decision.

(12) A Resource Entity and TSP may enter into an agreement in which the Generation Resource or ESR compensates the TSP to provide VSS to meet the Reactive Power requirements of paragraph (4) above in part or in whole. The TSP shall certify to ERCOT that the agreement complies with the Reactive Power requirements of paragraph (4).

(13) Unless specifically approved by ERCOT, no unit equipment replacement or modification at a Generation Resource or ESR shall reduce the capability of the unit below the Reactive Power requirements that applied prior to the replacement or modification. The addition of 20 MW or more of Load to a site that includes one or more Generation Resources or ESRs constitutes a modification to the Generation Resource or ESR that requires a new Reactive Power study.

(14) Generation Resources or ESRs shall not reduce high reactive loading on individual units during abnormal conditions without the consent of ERCOT unless equipment damage is imminent.

(15) All WGRs must provide a Real-Time SCADA point that communicates to ERCOT the number of wind turbines that are available for real power and Reactive Power injection into the ERCOT Transmission Grid. WGRs must also provide two other Real-Time SCADA points that communicate to ERCOT the following:

(a) The number of wind turbines that are not able to communicate and whose status is unknown; and

(b) The number of wind turbines out of service and not available for operation.

(16) All PhotoVoltaic Generation Resources (PVGRs) must provide a Real-Time SCADA point that communicates to ERCOT the capacity of PhotoVoltaic (PV) equipment that is available for real power and Reactive Power injection into the ERCOT Transmission Grid. PVGRs must also provide two other Real-Time SCADA points that communicate to ERCOT the following:

(a) The capacity of PV equipment that is not able to communicate and whose status is unknown; and

(b) The capacity of PV equipment that is out of service and not available for operation.

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| ***[NPRR1029: Insert paragraph (17) below upon system implementation and renumber accordingly:]***  (17) Each DC-Coupled Resource must provide a Real-Time SCADA point that communicates to ERCOT the capacity of the intermittent renewable generation component of the Resource that is available for real power and/or Reactive Power injection into the ERCOT System. Each DC-Coupled Resource must also provide Real-Time SCADA points that communicate to ERCOT the following:  (a) The capacity of any PV generation equipment that is not able to communicate and whose status is unknown;  (b) The capacity of any PV generation equipment that is out of service and not available for operation;  (c) The number of any wind turbines that are not able to communicate and whose status is unknown; and  (d) The number of any wind turbines out of service and not available for operation. |

(17) For the purpose of complying with the Reactive Power requirements under this Section 3.15, Reactive Power losses that occur on privately-owned transmission lines behind the POIB may be compensated by automatically switchable static VAr-capable devices.

3.15.1 ERCOT Responsibilities Related to Voltage Support

(1) ERCOT, in coordination with the TSPs, shall establish, and update as necessary, a Voltage Profile at the POIB for each Generation Resource and ESR 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 POIB 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.

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| ***[NPRR1098: Replace paragraph (3) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross Transmission LLC (Southern Cross) provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a Transmission Service Provider (TSP) and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (3) ERCOT, in coordination with TSPs, shall deploy static Reactive Power Resources as required to continuously maintain dynamic reactive reserves from QSEs and Direct Current Tie Operators (DCTOs), 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 points of interconnection for Load 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 points of interconnection for Load 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 POIB, 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 and Energy Storage Resource Requirements Related to Voltage Support

(1) Generation Resources and ESRs 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 and ESRs providing VSS shall be compliant with the ERCOT Operating Guides for response to transient voltage disturbance.

(3) Generation Resources and ESRs 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 and ESR 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 due to an undue threat to safety, undue risk of bodily harm, or undue damage to equipment at the generating plant.

(5) Each Generation Resource and ESR 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 or ESR’s operating characteristic limits, voltage limits, and within tolerances identified in paragraph (4) of Nodal Operating Guide Section 2.7.3.5, Resource Entity Responsibilities and Generation Resource and Energy Storage Resource Requirements.

(6) The reactive capability required must be maintained at all times that the Generation Resource or ESR 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. Each QSE shall send to ERCOT via telemetry the AVR status for each of its ESRs 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’ and ESRs’ 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.

(9) If any individual Resource within a Self-Limiting Facility is incapable of meeting its Reactive Power requirement at the POI, the QSE must bring On-Line additional Resource(s) within the Self-Limiting Facility to provide VSS as specified in paragraph (4) of Section 3.15, Voltage Support, while respecting the limit on MW Injection.

(10) The Resource Entity for an IRR synchronized to the ERCOT System that is not capable of providing Reactive Power when not producing real power shall:

(a) When capable of providing real power, set the IRR’s Low Sustained Limit (LSL) to 0 MW, or the lowest MW level, not to exceed 1 MW, at which the IRR can provide stable Reactive Power after appropriate tuning of settings;

(b) Ensure the lowest MW point on the submitted reactive capability curve reflects 0 MVAr leading and lagging reactive capability at 0 MW;

(c) Ensure the second-lowest MW point on the submitted reactive capability curve accurately reflects the IRR’s leading and lagging reactive capability at its LSL when the LSL is not 0 MW; and

(d) Send to ERCOT, via telemetry, an AVR status of “Off” when the IRR is synchronized to the ERCOT System and not producing Reactive Power.

(11) The Resource Entity for an IRR synchronized to the ERCOT System that is capable of providing any net Reactive Power when not producing real power shall:

(a) Provide stable Reactive Power output at all MW levels at which the IRR has Reactive Power capability;

(b) When capable of providing real power, set the IRR LSL to 0 MW or the lowest MW level, not to exceed 1 MW, at which the IRR can provide stable Reactive Power after appropriate tuning of settings;

(c) Ensure the lowest MW point on the submitted reactive capability curve accurately reflects the IRR’s MVAr leading and lagging reactive capability when not producing real power;

(d) Ensure the second-lowest MW point on the submitted reactive capability curve accurately reflects the IRR’s leading and lagging reactive capability at its LSL when the LSL is not 0 MW;

(e) Send to ERCOT, via telemetry, an AVR status of “On” when the IRR is synchronized to the ERCOT System, not producing real power, and reactive control is working properly; and

(f) Meet the requirements in paragraphs (2), (4), (5), and (7) above when the IRR is synchronized to the ERCOT System and not producing real power.

(12) The Resource Entity for an IRR that is capable of providing any net Reactive Power when not producing real power may physically desynchronize its inverters from the ERCOT System instead of providing Reactive Power when not producing real power.

(13) A Resource Entity shall submit a new Reactive Power study for a Generation Resource or ESR if 20 MW or more of Load is added to a site that includes the Generation Resource or ESR.

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| ***[NPRR1098: Insert Section 3.15.4 below upon system implementation and satisfying the following conditions: (1) Southern Cross Transmission LLC (Southern Cross) provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a Transmission Service Provider (TSP) and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  ***3.15.4 Direct Current Tie Owner and Direct Current Tie Operator (DCTO) Responsibilities Related to Voltage Support***  (1) The following Direct Current Ties (DC Ties) are subject to the Reactive Power capability requirements specified in these Protocols and the ERCOT Operating Guides:  (a) Any DC Tie with an initial energization date after January 1, 2021.  (b) Any DC Tie that is modified by increasing the physical capacity of the DC Tie by 20 MW or more or by changing the power converter associated with the DC Tie, unless the replacement is in-kind.  (2) The owner of a DC Tie meeting the applicability requirements of paragraph (1) above shall ensure that the DC Tie Facility has the following Reactive Power capabilities:  (a) An over-excited (lagging or producing) power factor capability of 0.95 or less determined at the DC Tie’s physical capacity at any voltage from 0.95 per unit to 1.04 per unit, as measured at the Point of Interconnection Bus (POIB);  (b) An under-excited (leading or absorbing) power factor capability of 0.95 or less determined at the DC Tie’s physical capacity at any voltage from 1.0 per unit to 1.05 per unit, as measured at the POIB;  (c) Reactive Power capability shall be available at all MW levels, whether injecting or withdrawing power, and may be met through a combination of the DC Tie’s dynamic leading and lagging operating capability and/or dynamic VAr-capable devices.  (3) The owner of a DC Tie meeting the applicability requirements of paragraph (1) above must conduct an engineering study demonstrating the ability of the DC Tie Facility to meet the Reactive Power requirements in paragraph (2) above. Any study results must be accepted by ERCOT prior to the initial energization date of the DC Tie.  (4) ERCOT may, with notice, require performance testing to demonstrate a DC Tie Facility’s ability to meet the Reactive Power requirements in paragraph (2) above.  (5) Each Direct Current Tie Operator (DCTO) operating a DC Tie Facility meeting the applicability requirements of paragraph (1) above shall comply with any instruction from its designated Transmission Operator (TO) with respect to the DC Tie’s reactive power capability, including any instruction to maintain a target voltage at the POIB, subject to the DC Tie’s operating characteristic limits and voltage limits, and within the tolerances identified in paragraph (2) of Nodal Operating Guide Section 2.7.3.6, DCTO Responsibilities and DC Tie Requirements, and subject to any superseding Dispatch Instruction from ERCOT.  (6) The owner of a DC Tie meeting the applicability requirements of paragraph (1) above shall implement a control system to control all devices at a DC Tie Facility needed to meet the Reactive Power requirements in paragraph (2) above.  (a) The control system shall be operated in automatic voltage control mode unless ERCOT directs the DCTO to operate the system in manual mode.  (b) The DCTO shall provide to its designated TO, via telemetry, the status of the control system. An “On” status will indicate that the control system is on and set to regulate the voltage at the DC Tie’s POIB in automatic voltage control mode, and an “Off” status will indicate that the control system is off or in manual mode. |

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:

(a) The percentage or MW limit of ERCOT Contingency Reserve Service (ECRS) allowed from Load Resources providing ECRS;

(b) The maximum amount (MW) of Responsive Reserve (RRS) that can be provided by Resources capable of Fast Frequency Response (FFR);

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| ***[NPRR1128: Replace item (b) above with the following upon system implementation:]***  (b) The maximum amount (MW) of Responsive Reserve (RRS) that can be provided by Resources capable of Fast Frequency Response (FFR) and specify the Operating Hours where prioritizing procurement of FFR up to the maximum FFR amount is beneficial in improving reliability; |

(c) 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

(d) The maximum amount (MW) of Regulation Down Service (Reg-Down) that can be provided by Resources providing Fast Responding Regulation Down Service (FRRS-Down).

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| ***[NPRR1007: Delete items (c) and (d) above upon system implementation of the Real-Time Co-Optimization (RTC) project and renumber accordingly.]*** |

(e) The minimum capacity required from Resources providing RRS using Primary Frequency Response shall not be less than 1,150 MW.

(3) The ERCOT Board shall review and recommend approval of ERCOT's methodology for determining the minimum Ancillary Service requirements, any minimum capacity required from Security-Constrained Economic Dispatch (SCED) dispatchable Resources to provide Non-Spinning Reserve (Non-Spin), the minimum capacity required from Resources providing Primary Frequency Response to provide RRS, the maximum amount of RRS that can be provided by Resources capable of FFR, the maximum amount of RRS that an individual Resource can provide using Primary Frequency Response, and the maximum amount of Reg-Up and Reg-Down that can be provided by Resources providing FRRS-Up and FRRS-Down. ERCOT shall post on the ERCOT website the ERCOT Methodologies for Determining Minimum Ancillary Service Requirements approved by the ERCOT Board. Any such recommendations require approval by the Public Utility Commission of Texas (PUCT) prior to implementation.

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| ***[NPRR1007, NPRR1128, NPRR1171, and NPRR1213: Replace applicable portions of paragraph (3) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1128, or NPRR1171; or upon system implementation and upon system implementation of NPRR1171 for NPRR1213:]***  (3) The ERCOT Board shall review and recommend approval of ERCOT's methodology for determining the minimum Ancillary Service requirements, any minimum capacity required from Security-Constrained Economic Dispatch (SCED) dispatchable Resources to provide Non-Spinning Reserve (Non-Spin), the maximum amount of Non-Spin that can be provided by Distribution Generation Resources (DGRs) and Distribution Energy Storage Resources (DESRs) that are interconnected to a distribution circuit that is subject to Load shed, the maximum amount of ECRS that can be provided by DGRs and DESRs that are interconnected to a distribution circuit that is subject to Load shed, the minimum capacity required from Resources providing Primary Frequency Response to provide RRS, the maximum amount of RRS that can be provided by Resources capable of FFR, the maximum amount of RRS that an individual Resource can provide using Primary Frequency Response, and the Operating Hours where prioritizing procurement of FFR up to the maximum FFR amount is beneficial in improving reliability. ERCOT shall post on the ERCOT website the ERCOT Methodologies for Determining Minimum Ancillary Service Requirements approved by the ERCOT Board. Any such recommendations require approval by the Public Utility Commission of Texas (PUCT) prior to implementation. |

(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 ERCOT website, 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.

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| ***[NPRR1007: Delete paragraph (4) above upon system implementation of the Real-Time Co-Optimization (RTC) project and renumber accordingly.]*** |

(5) Monthly, ERCOT shall determine and post on the ERCOT website 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, provided that RRS from Load Resources on high-set under-frequency relays and Resources providing FFR 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.

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| ***[NPRR1128: Replace paragraph (5) above with the following upon system implementation:]***  (5) Monthly, ERCOT shall determine and post on the ERCOT website 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, provided that RRS from Load Resources on high-set under-frequency relays and Resources providing FFR 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. ERCOT may add more Operating Hours where prioritizing procurement of FFR up to the maximum FFR amount is beneficial in improving reliability if it believes that these additional hours are vulnerable to low system inertia. ERCOT will issue an operations notice when such a change is made. |

(6) The amount of RRS that a Qualified Scheduling Entity (QSE) can self-arrange using a Load Resource excluding Controllable Load Resources (CLRs) and Resources providing FFR 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 Resources shall be limited to 60% of the total ERCOT RRS requirement.

(7) However, a QSE may offer 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 using the Load Resource 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) Monthly, ERCOT shall determine and post on the ERCOT website a minimum capacity required from Resources providing ECRS. The amount of Load Resources excluding CLRs that may or may not be on high-set under-frequency relays providing ECRS is limited to 50% of the total ERCOT ECRS requirement.

(9) The amount of ECRS that a QSE can self-arrange using a Load Resource excluding CLRs is limited to the lower of:

(a) 50% of its ECRS Ancillary Service Obligation; or

(b) A reduced percentage of its ECRS Ancillary Service Obligation based on the limit established by ERCOT in paragraph (8) above.

(10) A QSE may offer more of the Load Resource above the percentage limit established by ERCOT for sale of ECRS to other Market Participants. The total amount of ECRS using the Load Resource excluding CLRs procured by ERCOT is also limited to the lesser of the 50% limit or the limit established by ERCOT in paragraph (9) above.

(11) 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.

(12) 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.

(13) 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.

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| ***[NPRR1007: Delete paragraphs (11)-(13) above upon system implementation of the Real-Time Co-Optimization (RTC) project.]*** |

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.

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| ***[NPRR1007 and NPRR1246: Replace paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (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 or Energy Storage Resource (ESR) in discharge mode providing Reg-Up must be able to increase energy output when deployed and decrease energy output when recalled. A Load Resource or ESR in charge mode providing Reg-Up must be able to decrease Load when deployed and increase Load when recalled. ERCOT dispatches Reg-Up by a Load Frequency Control (LFC) signal. |

(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.

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| ***[NPRR1007 and NPRR1246: Replace paragraph (2) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (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 or ESR in discharge mode providing Reg-Down must be able to decrease energy output when deployed and increase energy output when recalled. A Load Resource or ESR in charge mode providing Reg-Down must be able to increase Load when deployed and decrease Load when recalled. ERCOT dispatches Reg-Down by an LFC signal. |

3.17.2 Responsive Reserve Service

(1) Responsive Reserve (RRS) is a service used to restore or maintain the frequency of the ERCOT System in response to a significant frequency deviation.

(2) RRS is automatically self-deployed by Resources in a manner that results in real power increases or decreases.

(3) RRS may be provided by:

(a) On-Line Generation Resource capable of providing Primary Frequency Response with the capacity excluding Non-Frequency Responsive Capacity (NFRC);

(b) Resources capable of providing Fast Frequency Response (FFR) and sustaining their response for up to 15 minutes;

(c) Load Resources controlled by high-set under-frequency relays;

(d) Controllable Load Resources (CLRs); and

(e) Generation Resources operating in synchronous condenser fast-response mode as defined in the Operating Guides.

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| ***[NPRR1246: Insert item (f) below upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (f) ESRs. |

3.17.3 Non-Spinning Reserve Service

(1) Non-Spinning Reserve (Non-Spin) 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 four consecutive hours;

(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 four consecutive hours; or

(c) Load Resources that are not Controllable Load Resources and are qualified for deployment by the operator using the Ancillary Service Deployment Manager and capable of:

(i) Reducing consumption based on an ERCOT Extensible Markup Language (XML) instruction within 30 minutes; and

(ii) Maintaining that deployment until recalled.

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| ***[NPRR1246: Insert item (d) below upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (d) ESRs. |

(2) The Non-Spin may be deployed by ERCOT to increase available reserves in Real-Time Operations.

***3.17.4 ERCOT Contingency Reserve Service***

(1) ERCOT Contingency Reserve Service (ECRS) is a service that is provided using capacity that can be sustained at a specified level for two consecutive hours and is used to restore or maintain the frequency of the ERCOT System:

(a) In response to significant depletion of RRS;

(b) As backup Regulation Service; and

(c) By providing energy to avoid getting into or during an Energy Emergency Alert (EEA).

(2) ECRS may be provided through one or more of the following means:

(a) From On-Line or Off-Line Resources as prescribed in the Operating Guides following 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) ECRS may be used to provide energy prior to or during the implementation of an EEA. ECRS provides Resource capacity, or capacity from interruptible Load available for deployment on ten minutes’ notice.

(4) ECRS may be provided by:

(a) Unloaded, On-Line Generation Resource capacity;

(b) Quick Start Generation Resources (QSGRs);

(c) Load Resources that may or may not be controlled by high-set, under-frequency relays;

(d) Controllable Load Resources; and

(e) Generation Resources operating in synchronous condenser fast-response mode as defined in the Operating Guides.

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| ***[NPRR1246: Insert item (f) below upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (f) ESRs. |

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), ERCOT Contingency Reserve Service (ECRS), Regulation Up Service (Reg-Up), Regulation Down Service (Reg-Down), and Non-Spinning Reserve (Non-Spin).

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| ***[NPRR1007 and NPRR1246: Replace paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (1) For Generation Resources, Energy Storage Resources (ESRs), 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 awards for Responsive Reserve (RRS), ERCOT Contingency Reserve Service (ECRS), Regulation Up Service (Reg-Up), Regulation Down Service (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.

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| ***[NPRR1007: Replace paragraph (2) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (2) For Non-Spin, the amount of Non-Spin awarded must be less than or equal to the HSL for Off-Line Generation Resources. |

(3) For RRS:

(a) The full amount of RRS using Primary Frequency Response awarded to or self-arranged from an On-Line Resource is dependent upon the verified droop characteristics of the Resource. ERCOT shall calculate and update, using the methodology described in Nodal Operating Guide Section 8, Attachment N, Procedure for Calculating RRS MW Limits for Individual Resources to Provide RRS Using Primary Frequency Response, a maximum MW amount of RRS using Primary Frequency Response for each Resource subject to verified droop performance. The default value for any newly qualified Resource not yet evaluated per Nodal Operating Guide Section 8, Attachment N shall be 20% of its HSL. A Private Use Network with a registered Resource may use the gross HSL for qualification and establishing a limit on the amount of RRS capacity that the Resource within the Private Use Network can provide;

(b) Generation Resources operating in the synchronous condenser fast-response mode may provide RRS up to the 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. Once deployed, a Resource telemetering a Resource Status of ONRR shall telemeter an RRS Ancillary Service Schedule of zero, and when recalled by ERCOT after frequency recovers above 59.98 Hz, such Resource shall telemeter an RRS Ancillary Service Schedule that shall be a non-zero value equal to its RRS Ancillary Service Responsibility;

(c) The initiation setting of the automatic under-frequency relay setting for Load Resources providing RRS shall not be lower than 59.70 Hz; and

(d) The amount of RRS provided from a Resource capable of providing Fast Frequency Response (FFR) must be less than or equal to its 15-minute rated capacity. The initiation setting of the automatic self-deployment of the Resource providing RRS as FFR must be no lower than 59.85 Hz. A Resource providing RRS as FFR that is deployed shall not recall its capacity until system frequency is greater than 59.98 Hz. Once deployed, a Resource telemetering a Resource Status of ONFFRRRS or ONFFRRRSL shall telemeter an RRS Ancillary Service Schedule of zero, and when recalled, such Resource shall telemeter an RRS Ancillary Service Schedule that shall be a non-zero value equal to its RRS Ancillary Service Responsibility. Once recalled, a Resource providing RRS as FFR must restore its full RRS Ancillary Service Resource Responsibility within 15 minutes after cessation of deployment or as otherwise directed by ERCOT.

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| ***[NPRR1007 and NPRR1246: Replace paragraph (3) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (3) For RRS:  (a) The full amount of RRS using Primary Frequency Response that can be provided by an On-Line Resource is dependent upon the verified droop characteristics of the Resource. ERCOT shall calculate and update, using the methodology described in Nodal Operating Guide Section 8, Attachment N, Procedure for Calculating RRS MW Limits for Individual Resources to Provide RRS Using Primary Frequency Response, a maximum MW amount of RRS using Primary Frequency Response for each Resource subject to verified droop performance. The default value for any newly qualified Resource not yet evaluated per Nodal Operating Guide Section 8, Attachment N shall be 20% of its HSL. A Private Use Network with a registered Resource may use the gross HSL for qualification and establishing a limit on the amount of RRS capacity that the Resource within the Private Use Network can provide;  (b) Generation Resources operating in the synchronous condenser fast-response mode may be awarded RRS up to the 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) The initiation setting of the automatic under-frequency relay setting for Load Resources providing RRS shall not be lower than 59.70 Hz; and  (d) The amount of RRS awarded to a Resource capable of providing Fast Frequency Response (FFR) must be less than or equal to its 15-minute rated capacity. The initiation setting of the automatic self-deployment of the Resource providing RRS as FFR must be no lower than 59.85 Hz. |

(4) For ECRS:

(a) The full amount of ECRS provided from an On-Line Generation Resource must be less than or equal to ten times the Emergency Ramp Rate;

(b) The full amount of ECRS provided by a Quick Start Generation Resource (QSGR) must be less than or equal to its proven ten-minute capability as demonstrated pursuant to paragraph (16) of Section 8.1.1.2, General Capacity Testing Requirements;

(c) Generation Resources operating in the synchronous condenser fast-response mode may provide ECRS up to the 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; and

(d) For any Load Resources controlled by under-frequency relay and providing ECRS, the initiation setting of the automatic under-frequency relay setting shall not be lower than 59.70 Hz. To provide ECRS, Load Resources are not required to be controlled by under-frequency relays.

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| ***[NPRR1007 and NPRR1246: Replace applicable portions of paragraph (4) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (4) For ECRS:  (a) The full amount of ECRS that can be awarded to an On-Line Generation Resource or ESR must be less than or equal to ten times the Emergency Ramp Rate;  (b) The full amount of ECRS that can be awarded to a Quick Start Generation Resource (QSGR) must be less than or equal to its proven ten-minute capability as demonstrated pursuant to paragraph (16) of Section 8.1.1.2, General Capacity Testing Requirements;  (c) Generation Resources operating in the synchronous condenser fast-response mode may be awarded ECRS up to the 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; and  (d) For any Load Resources controlled by under-frequency relay and awarded ECRS, the initiation setting of the automatic under-frequency relay setting shall not be lower than 59.70 Hz. To provide ECRS, Load Resources are not required to be controlled by under-frequency relays. |

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 (SWGRs), 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.

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| ***[NPRR1182: Insert paragraph (d) below upon system implementation:]***  (d) For Controllable Load Resources:  (i) Long-Term CCT - the maximum interruptible Load MW, as registered with ERCOT.  (ii) SCED CCT - the telemetered Maximum Power Consumption (MPC) minus the telemetered Low Power Consumption (LPC) for Resources with a telemetered Resource Status as specified in paragraph (5)(b)(iii) of Section 3.9.1, excluding Resources with a Resource Status of OUTL. |

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| ***[NPRR1182: Insert paragraph (e) below upon system implementation of NPRR1014 and NPRR1182:]***  (e) For Energy Storage Resources (ESRs):  (i) Long-Term CCT - the Seasonal net max sustainable rating minus the Seasonal net min sustainable rating, as registered with ERCOT.  (ii) SCED CCT - for Resources with a telemetered Resource Status as specified in paragraph (5)(b)(iv) of Section 3.9.1, excluding Resources with a Resource Status of OUT, the minimum of:  (A) The telemetered HSL minus the telemetered Low Sustained Limit (LSL) for the Resource; and  (B) The telemetered max State of Charge minus the min State of Charge for the Resource divided by 15 minutes. |

(4) “Managed Capacity for an Entity” is a Resource for which a Decision Making Entity (DME) has control over how the 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.

(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:

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| [NPRR1182: Replace paragraph (6) above with the following upon system implementation:]  (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, excluding Controllable Load 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: |

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| **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 a DME 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.

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| ***[NPRR1182: Replace paragraph (1) above with the following upon system implementation:]***  (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 Shift Factors that can help resolve the constraint by increasing power injection or reducing power withdrawal with absolute values greater than the minimum of one-third of the highest absolute value of any Resource Shift Factor meeting this criterion 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 DME on the import side.

(b) Determine the percentage of ECI Effective Capacity by each DME on the import side by taking each DME’s 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 DME 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 a DME during peak Load conditions; and

(c) There are negative Shift Factors corresponding to Electrical Buses with Available Capacity for a Resource that have an absolute value greater than or equal to SFP2.

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| ***[NPRR1182: Replace paragraph (c) above with the following upon system implementation:]***  (c) There are Shift Factors corresponding to Electrical Buses with Available Capacity for a Resource that can help resolve the constraint by increasing power injection or reducing power withdrawal that have an absolute value greater than or equal to SFP2. |

(4) Any constraint that is analyzed and does not meet the conditions in paragraph (3) above will be designated as a Non-Competitive Constraint for the monthly case.

(5) ERCOT shall update and post the list of Competitive Constraints identified by the Long-Term CCT on the MIS Secure Area. The list of Competitive Constraints shall be posted at least 30 days prior to the first of the year.

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| ***[NPRR1239: Replace paragraph (5) above with the following upon system implementation:]***  (5) ERCOT shall update and post the list of Competitive Constraints identified by the Long-Term CCT on the ERCOT website. 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 a DME. If the constraint cannot be resolved, then the DME 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

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| ***[NPRR1182: Replace paragraph (c) above with the following upon system implementation:]***  (c) There are Shift Factors corresponding to Electrical Buses with Available Capacity for a Resource that can help resolve the constraint by increasing power injection or reducing power withdrawal that have an absolute value greater than or equal to 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 DME and whether the DME 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 ERCOT website 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:

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| ***[NPRR1182: Replace paragraph (7) above with the following upon system implementation:]***  (7) Mitigation will be applied to a Resource, excluding Controllable Load Resources, 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 DME 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 binding in Real-Time on three or more Operating Days within a calendar month shall be considered to be experiencing chronic congestion.

3.20.1 Evaluation of Chronic Congestion

(1) ERCOT shall evaluate chronic congestion monthly and shall report the results of its evaluation to the appropriate Technical Advisory Committee (TAC) subcommittee(s). The report must identify the constraint(s) causing the chronic congestion.

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| ***[NPRR1240: Replace paragraph (1) above with the following upon system implementation:]***  (1) ERCOT shall evaluate chronic congestion monthly and shall report on the ERCOT website the results of its evaluation to the appropriate Technical Advisory Committee (TAC) subcommittee(s). The report must identify the constraint(s) causing the chronic congestion. |

3.20.2 Topology and Model Verification

(1) For constraints identified in the report required by Section 3.20.1, Evaluation of Chronic Congestion, ERCOT shall notify the appropriate Transmission Service Provider(s) (TSP(s)) or Resource Entity. The TSP or Resource Entity must verify that the data in the Network Operations Model and Updated Network Model is accurate, including the Ratings of the Transmission Facility causing the binding transmission constraint.

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| ***[NPRR857: Replace paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (1) For constraints identified in the report required by Section 3.20.1, Evaluation of Chronic Congestion, ERCOT shall notify the appropriate Transmission Service Provider(s) (TSP(s)), Direct Current Tie Operator (DCTO), or Resource Entity. The TSP, DCTO, or Resource Entity must verify that the data in the Network Operations Model and Updated Network Model is accurate, including the Ratings of the Transmission Facility causing the binding transmission constraint. |

(2) If ERCOT determines that the Network Operations Model, the Updated Network Model, or the configuration of the Transmission Facility may be inaccurate, ERCOT shall coordinate with the owner of the Transmission Facility to determine if the Ratings should be updated, as provided by paragraph (3) of Section 3.10, Network Operations Modeling and Telemetry.

3.21 Submission of Declarations of Natural Gas Pipeline Coordination

(1) As part of its submission to ERCOT in connection with subsection (c)(3)(B) of P.U.C. Subst. R. 25.55, Weather Emergency Preparedness, each Resource Entity representing one or more Generation Resources subject to P.U.C. Subst. R. 25.55 that uses natural gas as its primary fuel shall submit to ERCOT the declaration in Section 22, Attachment K, Declaration of Natural Gas Pipeline Coordination, stating that the Resource Entity or its Qualified Scheduling Entity (QSE) made a documented effort to communicate with the operator of each natural gas pipeline directly connected to its Generation Resource to coordinate regarding potential impacts to the Generation Resource’s availability during the summer Peak Load Season of that year.

(2) If a Resource Entity or its QSE knows an activity or condition related to a natural gas pipeline directly connected to its Generation Resource will cause the Generation Resource’s unavailability, in whole or in part, the QSE shall, as soon as practicable, report that Outage or derate in the ERCOT Outage Scheduler in accordance with Section 3.1, Outage Coordination. An Outage or derate reported in the ERCOT Outage Scheduler need not be disclosed in the declaration contained in Section 22, Attachment K, nor reported under paragraph (4) below.

(3) If, before a Resource Entity submits the declaration contained in Section 22, Attachment K, the Resource Entity or its QSE is notified by an operator of a natural gas pipeline directly connected to its Generation Resource of an activity or condition (e.g. maintenance, inspection, malfunction, or third-party damage) that may limit or impede normal deliveries but is uncertain whether the activity or condition during the upcoming summer Peak Load Season will cause the Generation Resource to take an Outage or derate, the Resource Entity shall disclose the natural gas pipeline activity or condition in the declaration contained in Section 22, Attachment K, if the activity or condition materially increases the risk of Generation Resource unavailability during the summer Peak Load Season. The Resource Entity shall use its reasonable judgment to determine whether there is a material increase in the risk of unavailability.

(4) If, after submitting the declaration contained in Section 22, Attachment K, any previously disclosed information changes or a Resource Entity or its QSE receives new information about an activity or condition that may limit or impede normal natural gas deliveries and materially increases the risk of Generation Resource unavailability during the summer Peak Load Season, the Resource Entity shall disclose that information to ERCOT as soon as practicable. The Resource Entity shall use reasonable judgment to determine the risk of unavailability. When notifying ERCOT as required under this paragraph, the Resource Entity shall update the information required by paragraphs (3)(a)-(e) of the Natural Gas Pipeline Coordination section of Section 22, Attachment K, for the affected Generation Resource by sending an email to the email address designated by ERCOT.

(5) In complying with its obligations in this Section 3.21, a Resource Entity or its QSE relies upon communications with and information received from operators of natural gas pipelines directly connected to the Resource Entity’s Generation Resource. The Resource Entity or its QSE shall act in good faith to request the required information and, as soon as practicable, share with each other any information received from a natural gas pipeline operator required to be disclosed to ERCOT under Section 3.21. The Resource Entity or its QSE need not warrant the accuracy or completeness of information received from the natural gas pipeline operator and subsequently disclosed to ERCOT.

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.

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| ***[NPRR1234: Replace Section 3.22 above with the following upon system implementation:]***  **3.22 Subsynchronous Oscillation**  (1) All series capacitors shall have automatic Subsynchronous Oscillation (SSO) protective relays installed and shall have remote bypass capability.  The SSO 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.

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| ***[NPRR1234: Replace Section 3.22.1 above with the following upon system implementation:]***  ***3.22.1*** ***Subsynchronous Oscillation Vulnerability Assessment***  (1) In the SSO 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.  (2) The SSO vulnerability assessment includes the SSR vulnerability assessment that is related to the interaction between Generation Resources and series capacitors. |

**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 capacitor(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.

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| ***[NPRR1234: Replace paragraph (b) above with the following upon system implementation:]***  (b) If during the topology check ERCOT determines that an existing Generation Resource will become radial to one or more series capacitors in the event of 14 or fewer concurrent transmission Outages, ERCOT shall perform a frequency scan assessment in accordance with Section 3.22.2, Subsynchronous Oscillation 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.

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| ***[NPRR1234: Replace paragraph (d) above with the following upon system implementation:]***  (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 fewer 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 SSO 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 or Energy Storage 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 or Energy Storage Resource (ESR) will become radial to a series capacitor(s) in the event of fewer than 14 concurrent transmission Outages.

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| ***[NPRR1234 and NPRR1246: Replace applicable portions of paragraph (1) above with the following upon system implementation of NPRR1234; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1246:]***  (1) In the security screening study for a Generation Interconnection or Modification (GIM), ERCOT will perform a topology-check and determine if the Generation Resource or Energy Storage Resource (ESR) will become radial to one or more series capacitors in the event of fewer than 14 concurrent transmission Outages. |

(2) If ERCOT identifies that a Generation Resource or ESR will become radial to a series capacitor(s) in the event of fewer 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 or ESR is not vulnerable to SSR, then the interconnecting TSP is not required to perform the SSR study. If an SSR study is conducted, the interconnecting TSP shall submit it to ERCOT upon completion and shall include any SSR mitigation plan developed by the IE that has been reviewed by the TSP.

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| ***[NPRR1234: Replace paragraph (2) above with the following upon system implementation:]***  (2) If ERCOT identifies that a Generation Resource or ESR will become radial to one or more series capacitors in the event of fewer 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 Oscillation 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 or ESR is not vulnerable to SSR, then the interconnecting TSP is not required to perform the SSR study. If an SSR study is conducted, the interconnecting TSP shall submit it to ERCOT upon completion and shall include any SSO Mitigation plan developed by the IE that has been reviewed by the TSP. |

(3) If the SSR study performed in accordance with paragraph (2) above indicates that the Generation Resource or ESR is vulnerable to SSR in the event of six or fewer concurrent transmission Outages, the IE shall develop an SSR mitigation plan, provide it to the interconnecting TSP for review and inclusion in the TSP’s SSR study report to be approved by ERCOT, and implement the SSR mitigation prior to Initial Synchronization.

(a) If the SSR study performed in accordance with paragraph (2) above indicates that the Generation Resource or ESR 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 or ESR 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 or ESR installs the ERCOT-approved SSR protection prior to Initial Synchronization.

(b) For any Generation Resource or ESR that satisfied Planning Guide Section 6.9 before September 1, 2020, if the SSR study performed in accordance with paragraph (2) above indicates that the Generation Resource or ESR is vulnerable to SSR in the event of five or six concurrent transmission Outages, the IE may elect not to develop or implement an SSR mitigation plan, in which case ERCOT shall implement SSR monitoring in accordance with Section 3.22.3, Subsynchronous Resonance Monitoring. The IE shall provide ERCOT written Notice of any such election before the Generation Resource or ESR achieves Initial Synchronization, and the Generation Resource or ESR shall not be permitted to proceed to Initial Synchronization until ERCOT has implemented SSR monitoring.

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| ***[NPRR1234: Replace paragraph (3) above with the following upon system implementation:]***  (3) If the SSR study performed in accordance with paragraph (2) above indicates that the Generation Resource or ESR is vulnerable to SSR in the event of six or fewer concurrent transmission Outages, the IE shall develop an SSO Mitigation plan, provide it to the interconnecting TSP for review and inclusion in the TSP’s SSR study report to be approved by ERCOT, and implement the SSO Mitigation prior to Initial Synchronization.  (a) If the SSR study performed in accordance with paragraph (2) above indicates that the Generation Resource or ESR is vulnerable to SSR in the event of four concurrent transmission Outages, the IE may install SSO Protection in lieu of SSO Mitigation, as required by paragraph (3) above, if:  (i) The Generation Resource or ESR satisfied Planning Guide Section 6.9, Addition of Proposed Generation to the Planning Models, between August 12, 2013 and March 20, 2015;  (ii) The SSO Protection is approved by ERCOT; and  (iii) The Generation Resource or ESR installs the ERCOT-approved SSO Protection prior to Initial Synchronization.  (b) For any Generation Resource or ESR that satisfied Planning Guide Section 6.9 before September 1, 2020, if the SSR study performed in accordance with paragraph (2) above indicates that the Generation Resource or ESR is vulnerable to SSR in the event of five or six concurrent transmission Outages, the IE may elect not to develop or implement an SSO Mitigation plan, in which case ERCOT shall implement SSR monitoring in accordance with Section 3.22.3, Subsynchronous Resonance Monitoring. The IE shall provide ERCOT written Notice of any such election before the Generation Resource or ESR achieves Initial Synchronization, and the Generation Resource or ESR shall not be permitted to proceed to Initial Synchronization until ERCOT has implemented SSR monitoring. |

(4) ERCOT shall respond with its comments or approval of an SSR study report, which should include any required SSR mitigation plan, within 30 days of receipt. ERCOT comments should be addressed as soon as practicable by the TSP, and any action taken in response to ERCOT’s comments on an SSR study report shall be subject to further ERCOT review and approval. Upon approval of the SSR study report, ERCOT shall notify the interconnecting TSP, and the interconnecting TSP shall provide the approved SSR study report to the IE.

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| ***[NPRR1234: Replace paragraph (4) above with the following upon system implementation:]***  (4) ERCOT shall respond with its comments or approval of an SSR study report, which should include any required SSO Mitigation plan, within 30 days of receipt. ERCOT comments should be addressed as soon as practicable by the TSP, and any action taken in response to ERCOT’s comments on an SSR study report shall be subject to further ERCOT review and approval. Upon approval of the SSR study report, ERCOT shall notify the interconnecting TSP, and the interconnecting TSP shall provide the approved SSR study report to the IE. |

**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, Addition of Proposed Generation to the Planning Models, at the time the Transmission Facilities are proposed.

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| ***[NPRR1234 and NPRR1246: Replace applicable portions of paragraph (1) above with the following upon system implementation for NPRR1234; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1246:]***  (1) For any proposed Transmission Facilities connecting to or operating at 345 kV, the TSP shall perform an SSO vulnerability assessment, including a topology-check and/or frequency scan assessment in accordance with Section 3.22.2, Subsynchronous Oscillation 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 SSO assessment for ERCOT’s review. For the purposes of this Section, a Generation Resource or ESR is considered an existing Generation Resource or ESR if it satisfies Planning Guide Section 6.9, Addition of Proposed Generation to the Planning Models, 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.

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| ***[NPRR1234 and NPRR1246: Replace applicable portions of paragraph (2) above with the following upon system implementation for NPRR1234; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1246:]***  (2) If while performing the independent review of a transmission project, ERCOT determines that the transmission project may cause an existing Generation Resource or ESR or a Generation Resource or ESR satisfying Planning Guide Section 6.9, an existing Large Load, or a Large Load satisfying Planning Guide Sections 9.4, LLIS Report and Follow-up, and 9.5, Interconnection Agreements and Responsibilities, at the time the transmission project is proposed to become vulnerable to SSO, ERCOT shall perform an SSO 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.

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| ***[NPRR1234: Replace paragraph (3) above with the following upon system implementation:]***  (3) If the frequency scan assessment in paragraphs (1) or (2) above indicates potential SSO 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 SSO assessment to confirm or refute the SSO 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.

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| ***[NPRR1234 and NPRR1246: Replace applicable portions of paragraph (4) above with the following upon system implementation for NPRR1234; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1246:]***  (4) Past SSO assessments may be used to determine the SSO vulnerability of a Generation Resource, ESR, or a Large Load if ERCOT, in consultation with the affected TSPs, determines the results of the past SSO 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.

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| ***[NPRR1234 and NPRR1246: Replace applicable portions of paragraph (5) above with the following upon system implementation for NPRR1234; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1246:]***  (5) If the SSR study confirms a Generation Resource or ESR is vulnerable to SSR in the event of four or fewer 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 SSO Mitigation on the ERCOT transmission system. The SSO 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 or ESR. |

(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.

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| ***[NPRR1246: Replace paragraph (6) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (6) If the SSR study confirms a Generation Resource or ESR 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 or ESR. |

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| ***[NPRR1234: Insert paragraphs (7) and (8) below upon system implementation and renumber accordingly:]***  (7) If the SSO study confirms a Large Load is vulnerable to SSO in the event of six or fewer concurrent transmission Outages, the TSP that owns the affected series capacitor(s) shall coordinate with ERCOT, the affected Interconnecting Large Load Entity (ILLE), and affected TSPs to develop and implement SSO Mitigation on the ERCOT transmission system. The SSO 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 Energization of the Large Load.  (8) If the SSO study confirms one or more transformers associated with the Large Load is vulnerable to Subsynchronous Ferroresonance (SSFR) in the event of one or more conditions listed below, the TSP that owns the affected series capacitor(s) shall coordinate with ERCOT, the affected ILLE, and affected TSPs to develop and implement SSO Mitigation on the ERCOT transmission system. The SSO 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 Energization of the Large Load.  (a) One single element outage;  (b) One common tower outage;  (c) Two single element outages;  (d) Two common tower outages; or  (e) One single element outage and one common tower outage. |

(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.

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| ***[NPRR1234: Insert Section 3.22.1.4 below upon system implementation and renumber accordingly:]***  **3.22.1.4 Large Load Interconnection Assessment**  (1) Upon completion of all requirements prescribed in Planning Guide Section 9.2.2, Submission of Large Load Project Information and Initiation of the Large Load Interconnection Study (LLIS), ERCOT shall perform a topology check to determine:  (a) If the Large Load will become radial to one or more series capacitors in the event of six or fewer concurrent transmission Outages; and  (b) Whether the Large Load or any associated Facilities are expected to be susceptible to SSO.  (2) ERCOT shall specify all of the information that is needed to perform the topology check detailed in paragraph (1) above, and provide this specification to the interconnecting TSP. The interconnecting TSP shall request this information from the ILLE and provide it to ERCOT once received. ERCOT shall not initiate the topology check until it receives the required information from the TSP.  (3) The interconnecting TSP shall perform a detailed SSO assessment for the Load connection in accordance with Section 3.22.2, Subsynchronous Oscillation Vulnerability Assessment Criteria, to determine SSO vulnerability, if ERCOT determines that:  (a) A Large Load is vulnerable to SSO in the event of six or fewer concurrent transmission Outages; or  (b) A transformer associated with a Large Load is vulnerable to SSFR in the event of the following:  (i) One single element outage;  (ii) One common tower outage;  (iii) Two single element outages;  (iv) Two common tower outages; or  (v) One single element outage and one common tower outage.  (4) The SSO study shall determine which system configurations create vulnerability to SSO. The interconnecting TSP shall submit both the study report and the model data used in the study to ERCOT upon completion of the study. The interconnecting TSP shall include in the study report any SSO Countermeasures that have been reviewed by the TSP.  (5) If the SSO study performed in accordance with paragraph (3) above indicates that the Load connection is vulnerable to SSO, the ILLE, in coordination with the interconnecting TSP, shall develop an SSO Countermeasure plan and the TSP shall include it in the SSO study report to be approved by ERCOT.  (6) ERCOT shall respond with its comments or approval of an SSO study report, which shall include any required SSO Countermeasure plan, within 30 days of receipt. ERCOT comments shall be addressed as soon as practicable by the TSP, and any action taken in response to ERCOT’s comments on an SSO study report shall be subject to further ERCOT review and approval. Upon approval of the SSO study report, ERCOT shall notify the interconnecting TSP.  (7) After ERCOT approval of the SSO study report, the ILLE, in coordination with the interconnecting TSP, shall implement the approved SSO Countermeasures prior to Initial Energization of the Large Load. |

**3.22.1.4 Annual SSR Review**

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| ***[NPRR1234: Replace Section 3.22.1.4 above with the following upon system implementation:]***  **3.22.1.5 Annual SSO Review** |

(1) ERCOT shall perform an SSR review annually. The annual review shall include the following elements:

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| ***[NPRR1234: Replace paragraph (1) above with the following upon system implementation:]***  (1) ERCOT shall perform an SSO 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.

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| ***[NPRR1234: Replace paragraph (a) above with the following upon system implementation:]***  (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 SSO 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.

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| ***[NPRR1234 and NPRR1246: Replace applicable portions of paragraph (b) above with the following upon system implementation for NPRR1234; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1246:]***  (b) If ERCOT identifies that a Generation Resource or ESR will become radial to series capacitors(s) in the event of 14 or fewer 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 or ESR 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 or ESR 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 or ESR is vulnerable to SSR in the event of four or fewer 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 SSO Mitigation on the ERCOT transmission system. The SSO 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 or ESR.  (iv) If the SSR study confirms the Generation Resource or ESR 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 or ESR.  (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. |

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| ***[NPRR1234: Insert paragraph (c) below upon system implementation:]***  (c) ERCOT shall perform a topology check to identify any Large Load that becomes radial to one or more series capacitors in the event of six or fewer concurrent transmission Outages. ERCOT shall prepare a report to summarize the results of the topology check and provide it to the affected TSP. ERCOT and the affected TSP shall determine a need for further evaluation.  (i) If an SSO study confirms the Large Load or any associated Facilities are vulnerable to SSO and this risk was not previously identified during any study required by Section 3.22.1.4, the TSP that owns the affected series capacitor shall conduct more detailed study by coordinating with ERCOT, the affected ILLE, and affected TSPs to develop and install SSO Countermeasures on the ERCOT transmission system. The SSO Countermeasures shall be implemented prior to the latter of the energization of the transmission project or Initial Energization of the Large Load.  (ii) The interconnecting TSP shall submit both the detailed study report and the model data used in the detailed study to ERCOT upon completion of the study. The interconnecting TSP shall include in the study report any SSO Countermeasures that have been reviewed by the TSP. |

3.22.2 Subsynchronous Resonance Vulnerability Assessment Criteria

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| ***[NPRR1234: Replace Section 3.22.2 above with the following upon system implementation:]***  ***3.22.2 Subsynchronous Oscillation 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.

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| ***[NPRR1234 and NPRR1246: Replace applicable portions of paragraph (1) above with the following upon system implementation for NPRR1234; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1246:]***  (1) A Generation Resource or ESR is considered to be potentially vulnerable to SSR in the topology-check if the Generation Resource or ESR will become radial to one or more series capacitors in the event of 14 or fewer 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. |

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| ***[NPRR1234: Insert paragraph (2) below upon system implementation and renumber accordingly:]***  (2) A Large Load is considered to be potentially vulnerable to SSO in the topology check if:  (a) A Large Load will become radial to one or more series capacitors in the event of six or fewer concurrent transmission Outages; or  (b) A transformer associated with a Large Load will become radial to one or more series capacitors in the event of the following:  (i) One single element outage;  (ii) One common tower outage;  (iii) Two single element outages;  (iv) Two common tower outages; or  (v) One single element outage and one common tower outage. |

(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:

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| ***[NPRR1246: Replace paragraph (2) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (2) In determining whether a Generation Resource or ESR 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.

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| ***[NPRR1234 and NPRR1246: Replace applicable portions of paragraph (3) above with the following upon system implementation for NPRR1234; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1246:]***  (3) The detailed SSO assessment shall include an electromagnetic transient program analysis or similar analysis. A Generation Resource, ESR, or Large Load is considered to be vulnerable to SSO if any of the following criteria are met:  (a) For a Generation Resource, 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) For a Generation Resource, an ESR, or a Large Load, the oscillation, if any, is not damped; or  (c) For a Generation Resource, an ESR, or a Large Load, the oscillation, if any, results in disconnection of any transmission or 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.

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| ***[NPRR1234 and NPRR1246: Replace applicable portions of paragraph (2) above with the following upon system implementation for NPRR1234; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1246:]***  (2) ERCOT’s responsibilities for SSR monitoring shall consist of the following activities if a Generation Resource or ESR is vulnerable to SSR in the event of five or six concurrent transmission Outages identified in the SSR vulnerability assessment and does not implement SSO 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 or ESR 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 or ESR being two contingencies away from SSR vulnerability, ERCOT shall take action to mitigate SSR vulnerability to the affected Generation Resource or ESR. 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 or ESR is equipped with SSR protection and has elected for ERCOT to forego action to mitigate SSO 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 or ESR 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 or ESR being two or fewer contingencies away from SSR vulnerability, ERCOT shall notify the QSE representing the affected Generation Resource or ESR 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) or ESR(s) are at least three contingencies away from SSR vulnerability. |

3.23 Agreements between ERCOT and other Control Area Operators

(1) Prior to executing any agreement with another Control Area Operator concerning coordination of Switchable Generation Resources (SWGRs), Direct Current Ties (DC Ties), Block Load Transfers (BLTs), or other operational issues, ERCOT shall, to the extent possible, provide Notice to all Market Participants of such agreement and at least 14 days to comment. Amendments or modifications to such existing agreements shall also comply with this provision.

(2) ERCOT shall consider all comments received in response to the Notice and, to the extent time allows, discuss its acceptance or rejection of comments with the Technical Advisory Committee (TAC) and the ERCOT Board prior to execution.

(3) ERCOT shall provide Notice to all Market Participants following execution of any such agreement within two Business Days.

3.24 Notification of Low Coal and Lignite Inventory Levels

(1) Each Qualified Scheduling Entity (QSE) representing a Generation Resource that uses coal or lignite as its primary fuel, except as provided in paragraph (2) below, shall notify ERCOT of the following:

(a) If the coal or lignite inventory level available for Real-Time operations is projected to fall below 15 days of operation at the High Sustained Limit (HSL) within the next 90 days, the QSE shall notify ERCOT within three days of such a projection and provide an explanation of any disruption to the coal or lignite supply. Notifications to ERCOT should be via email, sent to [FuelSupply@ERCOT.com](mailto:FuelSupply@ERCOT.com).

(b) If the coal or lignite inventory level available for Real-Time operations is projected to fall below 10 days of operation at the HSL within the next 90 days, the QSE shall notify ERCOT immediately of such a projection, provide an explanation of any disruption to the coal or lignite supply, and provide daily inventory updates to ERCOT until the inventory level projection increases above 15 days. Notifications to ERCOT should be via email, sent to [FuelSupply@ERCOT.com](mailto:FuelSupply@ERCOT.com).

(2) The requirements of paragraph (1) above do not apply to a QSE of a Generation Resource that uses coal or lignite as its primary fuel if the Generation Resource is located within 15 miles proximity of its fuel supply or was originally designed to be located within 15 miles proximity of its fuel supply and does not have the capability of storing onsite inventory for at least 30 days of operation at the HSL. The QSE of a Generation Resource located within 15 miles of its fuel supply or that was originally designed to be located within 15 miles proximity of its fuel supply and does not have the capability of storing onsite inventory for at least 30 days of operation at the HSL must notify ERCOT of any disruption to the coal or lignite supply operations that could impact operations of the Generation Resource within two days of such disruption and provide an explanation of such disruption. Notifications to ERCOT should be via email, sent to [FuelSupply@ERCOT.com](mailto:FuelSupply@ERCOT.com).

3.25 Submission of Gas Supply Disruption

(1) A Qualified Scheduling Entity (QSE) that represents a Generation Resource that relies on natural gas as the primary fuel source shall use reasonable efforts to notify ERCOT when:

(a) A natural gas pipeline operator and/or natural gas fuel supplier issues either:

(i) A written notification to the QSE, or an affiliate of the Generation Resource or QSE responsible for buying natural gas for the Generation Resource, in accordance with a firm contract, indicating that a gas supply disruption on a natural gas pipeline directly connected to the Generation Resource represented by the QSE is projected to occur or is currently in progress, resulting in curtailment of natural gas deliveries to the Generation Resource; or

(ii) A written force majeure notice to the QSE, or an affiliate of the Generation Resource or QSE responsible for buying natural gas for the Generation Resource, on a natural gas pipeline directly connected to the Generation Resource represented by the QSE indicating a gas supply disruption; and

(b) The QSE determines that the Generation Resource’s ability to supply electricity will be significantly limited by the gas supply disruption. Notification under paragraph (1) will include a description of the potential impact to the operation of the Generation Resource.

(2) Notwithstanding paragraph (1) above, a QSE that represents a Generation Resource that relies on natural gas as the primary fuel source shall ensure that the High Sustained Limit (HSL) and Current Operating Plan (COP) accurately reflect the amount of output the Generation Resource can produce based on an amount of natural gas that the QSE expects it can procure after exploring all accessible and reasonable options.

(3) Notifications shall indicate which Generation Resources are reasonably expected to be impacted by the gas supply disruption based on the criteria above and the expected timeline of the disruption, based on available information.

(4) Notifications to ERCOT shall be via email, sent to [fuelsupply@ercot.com](mailto:fuelsupply@ercot.com).