(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.

(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) Notwithstanding paragraph (1) above, the following apply:

(a) For a Weather-Sensitive ERS Resource, the following shall apply:

(i) The maximum number of deployment events during an ERS Contract Period shall be equal to two times the number of months of weather-sensitive obligation in the ERS Contract Period.

(ii) The duration of a Weather-Sensitive ERS Load's deployment obligation time for a single event shall be a maximum of three hours.

[NPRR1090: Delete paragraph (3) above upon system implementation and renumber accordingly.]

(4) Unless ERCOT has received a notice of unavailability in a format prescribed by ERCOT, ERCOT shall assume that a contracted ERS Resource is fully available to provide ERS.

(5) QSEs and ERS Resources they represent shall meet the following technical requirements:

(a) Each ERS Resource, including each member of an aggregated ERS Resource, must have an ESI ID or Resource ID (RID) and dedicated metering, as defined by ERCOT. An ERS Resource located outside of a competitive service area may use

a unique service identifier in lieu of an ESI ID or RID. ERCOT shall analyze 15-minute interval meter data, adjusted for the deemed actual Distribution Loss Factors (DLFs), for each ERS Resource for purposes of offer analysis, availability and performance measurement. ERS Resources behind a NOIE meter point shall arrange, preferably with the NOIE TDSP, to provide ERCOT with 15-minute interval meter data subject to ERCOT's specifications and approval. ERS Resources behind a Private Use Network's Settlement Meter point shall provide ERCOT 15-minute interval meter data subject to ERCOT's specifications and approval. All generators in an ERS Resource must have TDSP metering capable of measuring energy exported to the ERCOT System and TDSP metering capable of measuring energy imported from the ERCOT System. The 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.

(6) The contracted capacity of ERS Resources may not be used to provide Ancillary Services during a contracted ERS Time Period. Nothing herein shall be construed to limit passive (voluntary) Load response, provided the ERS Resource meets its performance and availability requirements, as described in Section 8.1.3.1, Performance Criteria for Emergency Response Service Resources.

(7) QSEs representing ERS Resources must meet the requirements specified in Section 8.1.3.3, Payment Reductions and Suspension of Qualification of Emergency Response Service Resources and/or their Qualified Scheduling Entities.

3.14.3.4 Emergency Response Service Reporting and Market Communications

(1) ERCOT shall review the effectiveness and benefits of ERS every 12 months from the start of the program 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.

[NPRR885, NPRR995, and NPRR1007: 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:]

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 that was not included in the reliability need evaluation pursuant to paragraph (3)(a) of Section 3.14.1.2.

(i) Proposed Generation Resources 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, 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 Generator 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, 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.

[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.

[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.

[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.

[NPRR885: Insert Section 3.14.4.5 below upon system implementation:]

3.14.4.5 Standards for Generation Resource MRAs

(1) A Generation Resource 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 shall be committed by ERCOT VDI and Dispatched by SCED.

[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.

[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.

[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.

[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.

[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.

[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.

[NPRR885: Insert Section 3.14.4.7 below upon system implementation:]

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 to reflect conditions beyond the control of the Generation Resource MRA.

[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.

[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 Firm Fuel Supply Service (FFSS) 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 bids from QSEs for Generation Resources to provide FFSS. The RFP shall require bids to be submitted on or before September 1 of each year.

(3) QSEs may submit bids individually for one or more Generation Resources to provide FFSS using a bid submission form posted on the ERCOT website. A QSE may not submit a bid for a given Generation Resource unless it is the QSE designated by the Resource Entity associated with that Generation Resource. ERCOT must evaluate bids using criteria identified in an appendix to the RFP. ERCOT will issue FFSS awards for each Generation Resource 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 Resource, the FFSS Standby Fee awarded, the amount of reserved fuel associated with the FFSS award, and 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 second calendar year after the year in which the RFP is issued. A QSE may submit a bid for one or more Generation Resources to provide FFSS beginning in the same year the RFP is issued or beginning in a subsequent year covered by 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 bid submission form, the QSE shall disclose information including, but not limited to, the amount of reserved fuel offered, the MW available from the capacity offered, and each limitation of the offered Resource that could affect the Resource's ability to provide FFSS.

(b) When a Resource is selected to provide FFSS, the Resource shall complete all applicable testing requirements as specified in Section 8.1.1.2.1.6, Firm Fuel Supply Service Resource Qualification, Testing, and Decertification.

[NPRR1154: Replace paragraph (b) above with the following upon system implementation:]

(b) When a Resource is selected to provide FFSS, the Resource shall complete all applicable testing requirements as specified in Section 8.1.1.2.1.6, Firm Fuel Supply Service Resource Qualification, Testing, and Decertification. A QSE representing a FFSSR is allowed to provide the FFSS with an alternate Resource previously approved by ERCOT to replace the FFSSR.

(c) An offer to provide FFSS is an offer to supply an awarded amount of capacity, maintain an awarded amount of fuel, and to designate a specific number of emissions hours for which the awarded FFSSR is obligated to perform in the event that FFSS is deployed. Reserved fuel, emissions hours, and other attributes, in excess of the FFSS awards can be used at the discretion of the QSE as long as the awarded fuel reserves and emissions hours are maintained for the purposes of ERCOT deployment of FFSS.

(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 VDI to the QSE.

(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 award duration.

(f) The FFSSR shall continuously deploy FFSS to generate electricity until the earlier of (i) the exhaustion of the FFSS service duration as defined in the RFP, (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 and the FFSSR shall not be obligated to continue its FFSS deployment for the remainder of the Watch.

(g) A QSE shall notify ERCOT 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.

(h) 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) During or following the deployment of FFSS, the QSE for an FFSSR may request an approval from ERCOT to restock their fuel reserve to restore their FFSS capability. Following approval from ERCOT, a QSE may restock their FFSS obligation. In the event ERCOT does not receive the request to restock from a QSE representing an FFSSR, ERCOT may instruct QSE to start restocking fuel reserve to restore its FFSS capability.

(6) FFSSRs providing BSS must reserve FFSS capability in addition to 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.

(7) If ERCOT issues an FFSS VDI to an FFSSR for the same Operating Hour where a RUC instruction was issued, for Settlement, ERCOT will consider the RUC instruction as cancelled.

(8) ERCOT will provide a report to the TAC or its designated subcommittee within 45 days of any FFSS deployments, including the Resources deployed and the reason for the deployments.

(9) Any QSE that submits a bid 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 Control Area Operator during the period of the FFSS obligation.

(10) 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.

(2) All Generation Resources that are connected to Transmission Facilities (including self-serve generating units) and that have a gross generating unit rating greater than 20 MVA or those units connected at the same Point of Interconnection Bus (POIB) that have gross generating unit ratings aggregating to greater than 20 MVA, that supply power to the ERCOT Transmission Grid, shall provide Voltage Support Service (VSS).

[NPRR989: Replace paragraph (2) above with the following upon system implementation:]

(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.

[NPRR989: Replace paragraph (3) above with the following upon system implementation:]

(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 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 generating 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 generating 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 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 required to provide VSS is issued a new Voltage Set Point, that Generation Resource 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 Requirements;

(e) Reactive Power capability shall be available at all MW output levels and may be met through a combination of the Generation Resource's Unit Reactive Limit (URL), which is the generating unit's dynamic leading and lagging operating capability, and/or dynamic VAr-capable devices. This Reactive Power profile is depicted graphically as a rectangle. For Intermittent Renewable Resources (IRRs), the Reactive Power requirements shall be available at all MW output levels at or above 10% of the IRR's nameplate capacity. When an IRR is operating below 10% of its nameplate capacity and is unable to support voltage at the 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;

[NPRR989, NPRR1038, and NPRR1026: Replace applicable portions of paragraph (4) above with the following upon system implementation of NPRR989 for NPRR989 and NPRR1038; or upon system implementation for NPRR1026:]

(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 Energy Storage Resource (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 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.

[NPRR989: Replace paragraph (5) above with the following upon system implementation:]

(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 subject to Planning Guide Section 5.2.1, Applicability, a Generation Resource 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.

[NPRR989: Replace paragraph (6) above with the following upon system implementation:]

(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 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 generation units including IRRs shall, at a Generation Entity's option, be treated as a single Generation Resource if the units are connected to the same transmission bus.

[NPRR989: Replace paragraph (10) above with the following upon system implementation:]

(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) Generation Entities may submit to ERCOT specific proposals to meet the Reactive Power requirements established in paragraph (4) above by employing a combination of the URL and added VAr capability, provided that the added VAr capability shall be automatically switchable static and/or dynamic VAr devices. A Generation Resource and TSP may enter into an agreement in which the proposed static VAr devices can be switchable using Supervisory Control and Data Acquisition (SCADA). ERCOT may, at its sole discretion, either approve or deny a specific proposal, provided that in either case, ERCOT shall provide the submitter an explanation of its decision.

[NPRR989: Replace paragraph (11) above with the following upon system implementation:]

(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 Generation Resource and TSP may enter into an agreement in which the Generation Resource compensates the TSP to provide VSS to meet the Reactive Power requirements of paragraph (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).

[NPRR989: Replace paragraph (12) above with the following upon system implementation:]

(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 shall reduce the capability of the unit below the Reactive Power requirements that applied prior to the replacement or modification.

[NPRR989: Replace paragraph (13) above with the following upon system implementation:]

(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.

(14) Generation Resources shall not reduce high reactive loading on individual units during abnormal conditions without the consent of ERCOT unless equipment damage is imminent.

[NPRR989: Replace paragraph (14) above with the following upon system implementation:]

(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/or Reactive Power injection into the ERCOT Transmission Grid. WGRs must also provide two other Real-Time SCADA points that communicate to ERCOT the following:

[NPRR989: Replace paragraph (15) above with the following upon system implementation:]

(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/or Reactive Power injection into the ERCOT Transmission Grid. PVGRs must also provide two other Real-Time SCADA points that communicate to ERCOT the following:

[NPRR989: Replace paragraph (16) above with the following upon system implementation:]

(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.

[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 required to provide VSS to maintain system voltages within established limits.

[NPRR989: Replace paragraph (1) above with the following upon system implementation:]

(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.

[NPRR989: Replace paragraph (2) above with the following upon system implementation:]

(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.

[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 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 Requirements Related to Voltage Support

[NPRR989: Replace Section 3.15.3 above with the following upon system implementation:]

3.15.3 Generation Resource and Energy Storage Resource Requirements Related to Voltage Support

(1) Generation Resources required to provide VSS shall have and maintain Reactive Power capability at least equal to the Reactive Power capability requirements specified in these Protocols and the ERCOT Operating Guides.

[NPRR989: Replace paragraph (1) above with the following upon system implementation:]

(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 providing VSS shall be compliant with the ERCOT Operating Guides for response to transient voltage disturbance.

[NPRR989: Replace paragraph (2) above with the following upon system implementation:]

(2) Generation Resources and ESRs providing VSS shall be compliant with the ERCOT Operating Guides for response to transient voltage disturbance.

(3) Generation Resources providing VSS must meet technical requirements specified in Section 8.1.1.1, Ancillary Service Qualification and Testing, and the performance standards specified in Section 8.1.1, QSE Ancillary Service Performance Standards.

[NPRR989: Replace paragraph (3) above with the following upon system implementation:]

(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 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.

[NPRR989: Replace paragraph (4) above with the following upon system implementation:]

(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 providing VSS shall maintain the Voltage Set Point established by ERCOT, the interconnecting TSP, or the TSP's agent, subject to the Generation Resource's operating characteristic limits, voltage limits, and within tolerances identified in paragraph (4) of Nodal Operating Guide Section 2.7.3.5, Resource Entity Responsibilities and Generation Resource Requirements.

[NPRR989: Replace paragraph (5) above with the following upon system implementation:]

(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 Requirements.

(6) The reactive capability required must be maintained at all times that the Generation Resource is On-Line.

[NPRR989: Replace paragraph (6) above with the following upon system implementation:]

(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. For AVRs, an "On" status will indicate the AVR is on and set to regulate the Resource's terminal voltage in the voltage control mode, and an "Off" status will indicate the AVR is off or in a manual mode. For PSS, an "On" status will indicate the service is enabled and ready for service, and an "Off" status will indicate it is off or out of service. Each QSE shall monitor the status of its Generation Resources' regulators and stabilizers, and shall report status changes to ERCOT.

[NPRR989: Replace paragraph (7) above with the following upon system implementation:]

(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.

[NPRR1026: Insert paragraph (9) below upon system implementation and renumber accordingly:]

(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.

(9) 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.

(10) 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.

(11) 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.

[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:

[NPRR863: Insert item (a) below upon system implementation and renumber accordingly:]

(a) The percentage or MW limit of ERCOT Contingency Reserve Service (ECRS) allowed from Load Resources providing ECRS;

(a) The maximum amount (MW) of Responsive Reserve (RRS) that can be provided by Resources capable of Fast Frequency Response (FFR);

[NPRR1128: Replace item (a) above with the following upon system implementation:]

(a) 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;

(b) 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

(c) The maximum amount (MW) of Regulation Down Service (Reg-Down) that can be provided by Resources providing Fast Responding Regulation Down Service (FRRS-Down).

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

(d) 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 approve ERCOT's methodology for determining the minimum Ancillary Service requirements, any minimum capacity required from SCED dispatchable Resources to provide 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, and the maximum

amount of Reg-Up and Reg-Down that can be provided by Resources providing FRRS-Up and FRRS-Down.

[NPRR1007 and NPRR1128: 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:]

(3) The ERCOT Board shall review and approve ERCOT's methodology for determining the minimum Ancillary Service requirements, any minimum capacity required from SCED dispatchable Resources to provide 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, and the Operating Hours where prioritizing procurement of FFR up to the maximum FFR amount is beneficial in improving reliability.

(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.

[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 Market Information System (MIS) Secure Area a minimum capacity required from Resources providing RRS using Primary Frequency Response. The remaining capacity required for RRS may be supplied by all Resources qualified to provide RRS, 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.

[NPRR1128: Replace paragraph (5) above with the following upon system implementation:]

(5) Monthly, ERCOT shall determine and post on the Market Information System (MIS) Secure Area a minimum capacity required from Resources providing RRS using Primary Frequency Response. The remaining capacity required for RRS may be supplied by all Resources qualified to provide RRS, 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 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 RRS from Load Resources and Resources capable of providing FFR above the percentage limit established by ERCOT for sale of RRS to other Market Participants. The total amount of RRS Service using the Load Resource (excluding Controllable Load Resources) or Resources providing FFR 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.

[NPRR863: Replace paragraph (7) above with the following upon system implementation:]

(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.

[NPRR863: Insert paragraphs (8)-(10) below upon system implementation and renumber accordingly:]

(8) Monthly, ERCOT shall determine and post on the MIS Secure Area a minimum capacity required from Resources providing ECRS. The amount of Load Resources excluding Controllable Load Resources 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 Controllable Load Resources 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 Controllable Load Resources procured by ERCOT is also limited to the lesser of the 50% limit or the limit established by ERCOT in paragraph (9) above.

(8) The maximum MW amount of capacity from Resources providing FRRS-Up is limited to 65 MW. ERCOT may reduce this limit if it believes that this amount will have a negative impact on reliability or if this limit would require additional Regulation Service to be deployed.

(9) The maximum MW amount of capacity from Resources providing FRRS-Down is limited to 35 MW. ERCOT may reduce this limit if it believes that this amount will have a negative impact on reliability or if this limit would require additional Regulation Service to be deployed.

(10) Resources can only provide FRRS-Up or FRRS-Down if awarded Regulation Service in the Day-Ahead Market (DAM) for that particular Resource, up to the awarded quantity.

[NPRR1007: Delete paragraphs (8)-(10) 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.

[NPRR1007: 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 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. 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.

[NPRR1007: 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 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. 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:

(a) In response to, or to prevent, significant frequency deviations;

(b) As backup Regulation Service; and

(c) By providing energy during an Energy Emergency Alert (EEA).

(2) RRS may be provided through one or more of the following means:

(a) By using frequency-dependent response from On-Line Resources as prescribed in the Operating Guides to help restore the frequency within the first few seconds of an event that causes a significant frequency deviation in the ERCOT System; and

(b) Either manually or by using a four-second signal to provide energy on deployment by ERCOT.

(3) RRS may be used to provide energy during the implementation of an EEA. Under the EEA, RRS provides generation capacity, capacity from Controllable Load Resources or interruptible Load available for deployment on ten minutes' notice.

(4) RRS may be provided by:

(a) Unloaded, On-Line Generation Resource capacity;

(b) Load Resources controlled by high-set, under-frequency relays;

(c) Controllable Load Resources; and

(d) Hydro RRS as defined in the Operating Guides.

[NPRR863: Replace Section 3.17.2 above with the following upon system implementation:]

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; and

(d) Generation Resources operating in synchronous condenser fast-response mode as defined in the Operating Guides.

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.

(2) The Non-Spin may be deployed by ERCOT to increase available reserves in Real-Time Operations.

[NPRR863 and NPRR1096: Insert applicable portions of Section 3.17.4 below upon system implementation:]

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.

3.18 Resource Limits in Providing Ancillary Service

(1) For both Generation Resources and Load Resources the High Sustained Limit (HSL) must be greater than or equal to the Low Sustained Limit (LSL) and the sum of the Resource-specific designation of capacity to provide Responsive Reserve (RRS), Regulation Up (Reg-Up), Regulation Down (Reg-Down), and Non-Spinning Reserve (Non-Spin).

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

(1) 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 awards for Responsive Reserve (RRS), ERCOT Contingency Reserve Service (ECRS), Regulation Up (Reg-Up), Regulation Down (Reg-Down), and Non-Spinning Reserve (Non-Spin).

(2) For Non-Spin, the amount of Non-Spin provided must be less than or equal to the HSL for Off-Line Generation Resources.

[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 awarded to or self-arranged from an On-Line Generation Resource is dependent upon the verified droop characteristics of the Resource. ERCOT shall calculate and update, using the methodology described in the Nodal Operating Guide, a maximum MW amount of RRS for each Generation Resource subject to verified droop performance. The default value for any newly qualified Generation Resource 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.

[NPRR1007: 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 that can be provided by an On-Line Generation Resource is dependent upon the verified droop characteristics of the Resource. ERCOT shall calculate and update, using the methodology described in the Nodal Operating Guide, a maximum MW amount of RRS for each Generation Resource subject to verified droop performance. The default value for any newly qualified Generation Resource 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.

[NPRR863 and NPRR1007: Insert applicable portions of paragraph (4) below upon system implementation for NPRR863; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007:]

(4) For ECRS:

(a) The full amount of ECRS that can be awarded to an On-Line Generation Resource 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.

(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:

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.

(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.

(4) Any constraint that is analyzed and does not meet the conditions in paragraph (3) above will be designated as a Non-Competitive Constraint for the monthly case.

(5) ERCOT shall update and post the list of Competitive Constraints identified by the Long-Term CCT on the MIS Secure Area. The list of Competitive Constraints shall be posted at least 30 days prior to the first of the year.

3.19.4 Security-Constrained Economic Dispatch Constraint Competitiveness Test

(1) The SCED CCT uses current system conditions to evaluate the competitiveness of a constraint.

(2) Before each SCED execution, CCT is performed for all active constraints in SCED. The SCED CCT shall classify a constraint as competitive for the current SCED execution if the constraint meets all of the following conditions:

(a) The ECI is less than ECIT2 on the import side;

(b) The constraint can be resolved by eliminating all Available Capacity for a Resource on the import side, except nuclear capacity and minimum-energy amounts of coal and lignite capacity, that is Managed Capacity for 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

(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:

(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.

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.

[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.

3.22.1 Subsynchronous Resonance Vulnerability Assessment

(1) In the SSR vulnerability assessment, each transmission circuit is considered as a single Outage. A common tower Outage of two circuits or the Outage of a double-circuit transmission line will be considered as two transmission Outages.

3.22.1.1 Existing Generation Resource Assessment

(1) ERCOT shall perform a one-time SSR vulnerability assessment on all existing Generation Resources as described in paragraphs (a) through (f) below. For the purposes of this Section, a Generation Resource is considered an existing Generation Resource if it satisfies Planning Guide Section 6.9, Addition of Proposed Generation to the Planning Models, on or before August 12, 2013.

(a) ERCOT shall perform a topology-check on all existing Generation Resources.

(b) If during the topology-check ERCOT determines that an existing Generation Resource will become radial to a series 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.

(c) If the frequency scan assessment described in paragraph (b) above indicates potential SSR vulnerability, the Transmission Service Provider(s) (TSP(s)) that owns the affected series capacitor(s), in coordination with the interconnecting TSP, shall perform a detailed SSR analysis in accordance with Section 3.22.2 to determine SSR vulnerability, unless ERCOT, in consultation with and in agreement with of the affected TSP(s) and the affected Resource Entity, determines the frequency scan assessment is sufficient to determine the SSR vulnerability.

(d) If the SSR study performed in accordance with paragraph (b) and/or (c) above indicates that an existing Generation Resource is vulnerable to SSR in the event of four or less concurrent transmission Outages, the TSP(s) that owns the affected series capacitor(s) shall coordinate with the interconnecting TSP, ERCOT, and the affected Resource Entity to develop and implement SSR Mitigation on the ERCOT transmission system.

(e) If the SSR study performed in accordance with paragraph (b) and/or (c) above indicates that an existing Generation Resource is vulnerable to SSR in the event of five or six concurrent transmission Outages, ERCOT shall implement SSR monitoring in accordance with Section 3.22.3, Subsynchronous Resonance Monitoring.

(f) The Resource Entity shall provide sufficient model data to ERCOT within 60 days of receipt of the data request. ERCOT, at its sole discretion, may extend the response deadline.

3.22.1.2 Generation Resource 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.

(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.

(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.

(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.

3.22.1.3 Transmission Project Assessment

(1) For any proposed Transmission Facilities connecting to or operating at 345 kV, the TSP shall perform an SSR vulnerability assessment, including a topology-check and/or frequency scan assessment in accordance with Section 3.22.2, Subsynchronous Resonance Vulnerability Assessment Criteria. The TSP shall include a summary of the results of this assessment in the project submission to the Regional Planning Group (RPG) pursuant to Section 3.11.4, Regional Planning Group Project Review Process. For Tier 4 projects that include Transmission Facilities connecting to or operating at 345 kV, the TSP shall provide the SSR assessment for ERCOT's review. For the purposes of this Section, a Generation Resource is considered an existing Generation Resource if it satisfies Planning Guide Section 6.9 at the time the Transmission Facilities are proposed.

(2) If while performing the independent review of a transmission project, ERCOT determines that the transmission project may cause an existing Generation Resource or a Generation Resource satisfying Planning Guide Section 6.9 at the time the transmission project is proposed to become vulnerable to SSR, ERCOT shall perform an SSR vulnerability assessment, including topology-check and frequency scan in accordance with Section 3.22.2 if such an assessment was not included in the project submission. ERCOT shall include a summary of the results of this assessment in the independent review.

(3) If the frequency scan assessment in paragraphs (1) or (2) above indicates potential SSR vulnerability in accordance with Section 3.22.2, the TSP(s) that owns the affected series capacitor(s), in coordination with the TSP proposing the Transmission Facilities, shall perform a detailed SSR assessment to confirm or refute the SSR vulnerability.

(4) Past SSR assessments may be used to determine the SSR vulnerability of a Generation Resource if ERCOT, in consultation with the affected TSPs, determines the results of the past SSR assessments are still valid.

(5) If the SSR study confirms a Generation Resource is vulnerable to SSR in the event of four or less concurrent transmission Outages, the TSP that owns the affected series capacitor(s) shall coordinate with ERCOT, the affected Resource Entity, and affected TSPs to develop and implement SSR Mitigation on the ERCOT transmission system. The SSR Mitigation shall be developed prior to RPG acceptance, if required, and implemented prior to the latter of the energization of the transmission project or the Initial Synchronization of the Generation Resource.

(6) If the SSR study confirms a Generation Resource is vulnerable to SSR in the event of five or six concurrent transmission Outages, ERCOT shall implement SSR monitoring in accordance with Section 3.22.3, Subsynchronous Resonance Monitoring, prior to the latter of the energization of the transmission project or the Initial Synchronization of the Generation Resource.

(7) The Resource Entity shall provide sufficient model data to ERCOT within 60 days of receipt of the data request. ERCOT, at its sole discretion, may extend the response deadline.

3.22.1.4 Annual SSR Review

(1) ERCOT shall perform an SSR review annually. The annual review shall include the following elements:

(a) The annual review shall include a topology-check applying the system network topology that is consistent with a year 3 Steady State Working Group (SSWG) base case developed in accordance with Planning Guide Section 6.1, Steady-State Model Development. ERCOT shall post the SSR annual topology-check report to the Market Information System (MIS) Secure Area by May 31 of each year.

(b) If ERCOT identifies that a Generation Resource will become radial to series capacitors(s) in the event of less than 14 concurrent transmission Outages, ERCOT shall perform a frequency scan assessment in accordance with Section 3.22.2, Subsynchronous Resonance Vulnerability Assessment Criteria. ERCOT shall prepare a report to summarize the results of the frequency scan assessment and provide it to the Resource Entity and the affected TSP.

(i) If the frequency scan assessment described in paragraph (b) above shows the Generation Resource has potential SSR vulnerability in the event of six or fewer concurrent transmission Outages, the TSP(s) that owns the affected series capacitor compensated Transmission Element in coordination with the interconnecting TSP shall perform a detailed SSR assessment to confirm or refute the SSR vulnerability.

(ii) Past SSR assessments may be used to determine the SSR vulnerability of a Generation Resource if ERCOT, in consultation with the affected TSPs, determines the results of the past SSR assessments are still valid.

(iii) If the SSR study confirms the Generation Resource is vulnerable to SSR in the event of four or less concurrent transmission Outages, the TSP that owns the affected series capacitor compensated Transmission Element shall coordinate with ERCOT, the affected Resource Entity, and affected TSPs to develop and install SSR Mitigation on the ERCOT transmission system. The SSR Mitigation shall be developed, if required, and implemented prior to the latter of the energization of the transmission project or the Initial Synchronization of the Generation Resource.

(iv) If the SSR study confirms the Generation Resource is vulnerable to SSR in the event of five or six concurrent transmission Outages, ERCOT shall implement SSR monitoring in accordance with Section 3.22.3, Subsynchronous Resonance Monitoring, prior to the latter of energization of the transmission project or the Initial Synchronization of the Generation Resource.

(v) The Resource Entity shall provide sufficient model data to ERCOT within 60 days of receipt of the data request. ERCOT, in its sole discretion, may extend the response deadline.

3.22.2 Subsynchronous Resonance Vulnerability Assessment Criteria

(1) A Generation Resource is considered to be potentially vulnerable to SSR in the topology-check if a Generation Resource will become radial to a series capacitors(s) in the event of less than 14 concurrent transmission Outages. A frequency scan assessment and/or a detailed SSR assessment shall be required to screen for system conditions causing potential SSR vulnerability.

(2) In determining whether a Generation Resource is considered to be potentially vulnerable to SSR in the frequency scan assessment results, the following criteria shall be considered:

(a) Induction Generator Effect (IGE) and Subsynchronous Control Interaction (SSCI):

(i) When considering the total impedance of the generator and the applicable part of the ERCOT System, if the total resistance is negative at a reactance crossover of zero Ohms from negative to positive with increasing frequency, then the generator is considered to be potentially vulnerable to IGE/SSCI;

(b) Torsional Interaction:

(i) If the sum of the electrical damping (De) plus the mechanical damping (Dm) results in a negative value then the generator is potentially vulnerable to Torsional Interaction. Dm at +/- 1 Hz of the modal frequency may be utilized to compare to De; and

(c) Torque Amplification:

(i) When considering the total impedance of the generator and the ERCOT system, if a 5% or greater reactance dip, or a reactance crossover of zero Ohms from negative to positive with increasing frequency, occurs within a +/- 3 Hz complement of the modal frequency, then the generator is considered to be potentially vulnerable to Torque Amplification. The percentage of a reactance dip is on the basis of the reactance maximum at the first inflection point of the dip where the reactance begins to decrease with increasing frequency.

(3) The detailed SSR assessment shall include an electromagnetic transient program analysis or similar analysis. A Generation Resource is considered to be vulnerable to SSR if any of the following criteria are met:

(a) The SSR vulnerability results in more than 50% of fatigue life expenditure over the expected lifetime of the unit;

(i) If the fatigue life expenditure is not available, the highest torsional torque caused by SSR is more than 110% of the torque experienced during a transmission fault with the series capacitors bypassed;

(b) The oscillation, if occurred, is not damped; or

(c) The oscillation, if occurred, results in disconnection of any transmission and generation facilities.

3.22.3 Subsynchronous Resonance Monitoring

(1) For purposes of SSR monitoring, a common tower Outage loss of a double-circuit transmission line consisting of two circuits sharing a tower for 0.5 miles or greater is considered as one contingency.

(2) ERCOT's responsibilities for SSR monitoring shall consist of the following activities if a Generation Resource is vulnerable to SSR in the event of five or six concurrent transmission Outages identified in the SSR vulnerability assessment and does not implement SSR Mitigation:

(a) ERCOT shall identify the combinations of Outages of Transmission Elements that may result in SSR vulnerability and provide these Transmission Elements to the affected Resource Entity and its interconnected TSP;

(b) ERCOT shall monitor the status of these Transmission Elements identified in paragraph (a) above;

(c) If the occurrence of Forced and/or Planned Outages results in a Generation Resource being three contingencies away from SSR vulnerability, ERCOT will identify options for mitigation that would be implemented if an additional transmission Outage were to occur, including communications with TSPs to determine potential Outage cancellations and time estimates to reinstate Transmission Facilities;

(d) If the occurrence of Forced and/or Planned Outages results in a Generation Resource being two contingencies away from SSR vulnerability, ERCOT shall take action to mitigate SSR vulnerability to the affected Generation Resource. ERCOT shall consider the actions in the following order unless reliability considerations dictate a different order. Actions that may be considered are:

(i) No action if the affected Generation Resource is equipped with SSR Protection and has elected for ERCOT to forego action to mitigate SSR vulnerability;

(ii) Coordinate with TSPs to withdraw or restore an Outage within eight hours if feasible;

(iii) If the actions described in (i) and (ii) above are not feasible, ERCOT shall promptly take necessary steps to identify and mitigate the impacts to the ERCOT System caused by bypassing the affected series capacitor(s) and direct the TSP(s) to bypass the affected series capacitors(s); or

(iv) Other actions specific to the situation, including, but not limited to, Verbal Dispatch Instruction (VDI) to the Resource's Qualified Scheduling Entity (QSE).

(e) If the occurrence of Forced and/or Planned Outages results in a Generation Resource being one contingency away from SSR vulnerability, ERCOT shall promptly take necessary steps to identify and mitigate the impacts to the ERCOT System caused by bypassing the affected series capacitor(s) and direct the TSP(s) to bypass the affected series capacitor(s).

(f) If the occurrence of Forced and/or Planned Outages results in a Generation Resource being two or less contingencies away from SSR vulnerability, ERCOT shall notify the QSE representing the affected Generation Resource by voice communication as soon as practicable that the SSR vulnerability scenario has occurred; initiate the mitigation actions described in paragraphs (2)(d)(i) through (iv) above; and provide additional notifications to the QSE of each relevant topology change until the affected Generation Resource(s) is at least three contingencies away from SSR vulnerability.

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, 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.

ERCOT Nodal Protocols

Section 22

Attachment E: Notification of Suspension of Operations

April 1, 2023

Notification of Suspension of Operations of a Generation Resource

This Notification is required for providing notification of any Generation Resource suspension lasting greater than 180 days. Information may be inserted electronically to expand the reply spaces as necessary.

The Notification must be signed, notarized and delivered to ERCOT. Delivery may be accomplished via email to MPRegistration@ercot.com (if a scanned copy) or via facsimile (Attention: Market Participant Registration) at (512) 225-7079.

ERCOT may request additional information as reasonably necessary to support operations under the ERCOT Protocols.

Part I:

Resource Entity: _____

DUNS Number: _____

Resource Site Name: _____

Resource Site Location (County): _____

Unit Name(s): _____

Resource Name(s) (Unit Code/Mnemonic): _____

ESI ID: _____

Seasonal Net Max Sustainable Rating – Summer (MW): _____

Seasonal Net Minimum Sustainable Rating – Summer (MW): _____

Transmission Facilities that will be deactivated or removed from service as part of the suspension of operations of the unit(s): _____

Part II:

As of [Date],[1] the Generation Resource(s) will be limited or unavailable for Dispatch by ERCOT because Resource Entity will [check one]:

☐ decommission and retire the Generation Resource(s) permanently for a reason other than a Forced Outage,[2]

☐ suspend operation on a year-round basis (*i.e.*, mothball) and begin operation on a seasonal basis with a Seasonal Operation Period that begins on [Date] and ends on [Date]. The Seasonal Operation Period must be inclusive of June 1 through September 30,

☐ temporarily suspend operation (*i.e.*, mothball) of the Generation Resource(s) for a period of not less than ___ months and not greater than ___ months due to some reason other than a Forced Outage, or

☐ indefinitely suspend operation (*i.e.*, mothball) of the Generation Resource(s).

On [Date], the Generation Resource experienced a Forced Outage. As a result of the Forced Outage, the Resource Entity intends to [check one]:

☐ decommission and retire the Generation Resource(s) permanently,**Error! Bookmark not defined.**

☐ temporarily suspend operation of the Generation Resource(s), with an estimated return date of [Date], or

☐ indefinitely suspend operation (*i.e.*, mothball) of the Generation Resource(s).

Check if applicable: ☐ Resource Entity believes that this Generation Resource(s) is inoperable due to emissions limitations or not being repairable.

Operational and Environmental Limitations (check and describe all that apply):

(a) Operational:

☐ Maximum annual hours of operation: _____

☐ Maximum annual MWhs: _____

☐ Maximum annual starts: _____

☐ Other: _____

[1] Pursuant to Protocol Section 3.14.1.1, Notification of Suspension of Operations, this date must be at least 150 days (or 90 days if the Generation Resource will mothball and operate under a Seasonal Operation Period) from the date ERCOT receives this Notification.

[2] ERCOT will remove the Generation Resource(s) from its registration systems if this option is selected.

(b) Environmental:

☐ Maximum annual NOx emissions: _____

☐ Maximum annual SO2 emissions: _____

☐ Other: _____

Part III:

Estimated RMR Fuel Adder ($/MMBtu): _____

Proposed Initial Standby Cost ($/hr): _____

I understand and agree that this Notification is not confidential and does not constitute Protected Information under the ERCOT Protocols.

I hereby certify that the proposed, estimated Fuel Adder, Standby Costs, and attached budget are accurate at the time of submittal, necessary, and do not exceed fair-market value.

The undersigned certifies that I am an officer or executive of Resource Entity, that I am authorized to execute and submit this Notification on behalf of Resource Entity, and that the statements contained herein are true and correct.

_____

Name: _____

Title: _____

Date: _____

STATE OF _____

COUNTY OF _____

Before me, the undersigned authority, this day appeared _____, known by me to be the person whose name is subscribed to the foregoing instrument, who, after first being sworn by me deposed and said:

> "I am an officer of _____, I am authorized to execute and submit the foregoing Notification on behalf of _____, and the statements contained in such Notification are true and correct."

SWORN TO AND SUBSCRIBED TO BEFORE ME, the undersigned authority on this the _____ day of _____, 20__.

_____

Notary Public, State of _____

My Commission expires _____

ATTACHMENT D

ERCOT Nodal Protocols

Section 2: Definitions and Acronyms

April 1, 2023

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2 DEFINITIONS AND ACRONYMS

The list of acronyms is at the end of this Definitions Section.

2.1 DEFINITIONS

Definitions are supplied for terms used in more than one Section of the Protocols. If a term is used in only one Section, it is defined there at its earliest usage.

LINKS TO DEFINITIONS:

A, B, C, D, E, F, G, H, I, J, K, L, M, N, O, P, Q, R, S, T, U, V, W, X, Y, Z;

List of Acronyms

A

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Adjusted Metered Load (AML)

Retail Load usage data that has been adjusted for Unaccounted for Energy (UFE), Transmission Losses, Distribution Losses, and Direct Current Tie (DC Tie) exports.

Adjusted Static Models

Load Profiles that are generated from statistical models that are based on static historical Load data, and adjusted for conditions of the day (e.g., weather, Season, etc.).

Adjustment Period

For each Operating Hour, the time between 1800 in the Day-Ahead up to the start of the hour before that Operating Hour.

Advance Action Notice (AAN)

A type of Operating Condition Notice (OCN) that identifies a possible future Emergency Condition and describes future action ERCOT expects to take to address that condition unless the need for ERCOT action is alleviated by Qualified Scheduling Entity (QSE) and/or Transmission Service Provider (TSP) actions or by other system developments.

Advanced Meter

Any new or appropriately retrofitted meter that functions as part of a system that includes such meters and the associated hardware, software, and communications devices, that collects time-differentiated energy usage, and that is deployed pursuant to P.U.C. SUBST. R. 25.130, Advanced Metering.

Advanced Metering System (AMS)

A system, including Advanced Meters and the associated hardware, software, and communications devices, that collects time-differentiated energy usage and is deployed pursuant to P.U.C. SUBST. R. 25.130, Advanced Metering.

Advisory

The second of three levels of communication issued by ERCOT in anticipation of a possible Emergency Condition.

Affiliate

(1) An Entity that directly or indirectly owns or holds at least 5% of the voting securities of a Market Participant; or

(2) An Entity in a chain of successive ownership of at least 5% of the voting securities of a Market Participant; or

(3) An Entity that has at least 5% of its voting securities owned or controlled, directly or indirectly, by a Market Participant; or

(4) An Entity that has at least 5% of its voting securities owned or controlled, directly or indirectly, by an Entity who directly or indirectly owns or controls at least 5% of the voting securities of a Market Participant or an Entity in a chain of successive ownership of at least 5% of the voting securities of a Market Participant; or

(5) A person who is an officer or director of a Market Participant or of a corporation in a chain of successive ownership of at least 5% of the voting securities of a Market Participant.

(6) Notwithstanding any part of this definition, any Entity that would be considered an Affiliate due to its participation in a chain of successive ownership of a Market Participant shall not for that reason be considered an Affiliate if:

(a) It does not own 50% or more of the voting securities of any other Entity in the chain; or

(b) Its participation in the chain is only as a successive owner of an Entity in the chain that does not own 50% or more of the voting securities of another Entity in that chain.

(7) Provided that the Entity holding ownership or control of voting securities in a Market Participant does not hold such ownership or control for the purpose of exercising or influencing control of that Market Participant, then for the purposes of that relationship, the term "Entity," as used in this definition, shall not include:

(a) A broker or dealer registered under the Securities Exchange Act of 1934, 15 U.S.C. § 78;

(b) A bank or insurance company as defined under the Securities Exchange Act of 1934, 15 U.S.C. § 78;

(c) An investment adviser registered under state law or the Investment Advisers Act of 1940, 15 U.S.C. §§ 80b1-80b21;

(d) An investment company registered under the Investment Company Act of 1940, 15 U.S.C. §§ 80a1-80a64; or

(e) An employee benefit plan, pension fund, endowment fund, or other similar entity.

(8) ERCOT may request either of the following as conclusive evidence of the purpose required in paragraph (7) above:

(a) An affidavit attesting to that purpose if such affidavit is signed by the Entity owning the securities; or

(b) A report reflecting that purpose filed by the owning entity with the Securities and Exchange Commission.

(9) Notwithstanding any other provision of this Section 2.1, "Affiliate" includes any Entity determined by the Public Utility Commission of Texas (PUCT) to be an Affiliate.

Aggregate Generation Resource (AGR) (*see* Resource Attribute)

Aggregate Load Resource (ALR) (*see* Resource)

Agreement

A signed written agreement between ERCOT and a Market Participant using one of the standard form agreements in Section 22, Attachments, including those agreements containing changes to the standard form, which changes have been approved by the ERCOT Board.

Alternative Dispute Resolution (ADR)

Procedures, outlined in Section 20, Alternative Dispute Resolution Procedure, for settling disputes by means other than litigation.

Ancillary Service

A service necessary to support the transmission of energy to Loads while maintaining reliable operation of the Transmission Service Provider's (TSP's) transmission system using Good Utility Practice.

[NPRR857: Replace the above definition "Ancillary Service" 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:]

Ancillary Service

A service necessary to support the transmission of energy to Loads while maintaining reliable operation of the transmission system using Good Utility Practice.

Ancillary Service Assignment

Ancillary Service Resource Responsibility assigned to an On-Line Resource pursuant to paragraph (4) of Section 6.5.9.3.3, Watch.

[NPRR1013: Delete the above definition "Ancillary Service Assignment" upon system implementation of the Real-Time Co-Optimization (RTC) project.]

Ancillary Service Capacity Monitor

A set of processes described in Section 8.1.1.3, Ancillary Service Capacity Compliance Criteria, to determine the Real-Time capability of Resources to provide Ancillary Service.

[NPRR1013: Insert the following definition "Ancillary Service Demand Curve (ASDC)" upon system implementation of the Real-Time Co-Optimization (RTC) project:]

Ancillary Service Demand Curve (ASDC)

A curve that reflects the value of each Ancillary Service product by price/quantity pairs for each hour of the Operating Day.

[NPRR1013: Insert the following definition "Ancillary Service Imbalance" upon system implementation of the Real-Time Co-Optimization (RTC) project:]

Ancillary Service Imbalance

The difference between the amount of an Ancillary Service cleared in the Day-Ahead Market (DAM) and through trades and the amount of that Ancillary Service awarded in the Real-Time Market (RTM).

Ancillary Service Obligation

For each Ancillary Service, a Qualified Scheduling Entity's (QSE's) ERCOT-allocated share of total ERCOT System needs for that Ancillary Service.

Ancillary Service Offer

An offer to supply Ancillary Service capacity in the Day-Ahead Market (DAM) or a Supplemental Ancillary Service Market (SASM).

[NPRR1013: Replace the definition "Ancillary Service Offer" above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

Ancillary Service Offer

An offer to supply Ancillary Service capacity in the Day-Ahead Market (DAM) or Real-Time Market (RTM).

Resource-Specific Ancillary Service Offer

A Resource-specific offer to supply Ancillary Service capacity in the Day-Ahead Market (DAM) or Real-Time Market (RTM).

Ancillary Service Only Offer

An offer to sell Ancillary Service capacity in the Day-Ahead Market (DAM) that is not associated with a specific Resource.

Ancillary Service Plan

A plan produced by ERCOT, as described in Section 4.2.1, Ancillary Service Plan and Ancillary Service Obligation, which identifies the types and amount of Ancillary Service necessary for each hour of the Operating Day.

[NPRR1013: Insert the following definition "Ancillary Service Position" upon system implementation of the Real-Time Co-Optimization (RTC) project:]

Ancillary Service Position

The net amount of Ancillary Service capacity to which a Qualified Scheduling Entity (QSE) has financially committed in the ERCOT market, as described in Section 5.4.1, Ancillary Service Positions.

Ancillary Service Resource Responsibility

The MW of an Ancillary Service that each Resource is obligated to provide in Real-Time rounded to the nearest MW.

[NPRR1013: Delete the above definition "Ancillary Service Resource Responsibility" upon system implementation of the Real-Time Co-Optimization (RTC) project.]

Ancillary Service Schedule

The MW of each Ancillary Service that each Resource is providing in Real-Time and the MW of each Ancillary Service for each Resource for each hour in the Current Operating Plan (COP).

[NPRR1013: Delete the above definition "Ancillary Service Schedule" upon system implementation of the Real-Time Co-Optimization (RTC) project.]

Ancillary Service Supply Responsibility

The net amount of Ancillary Service capacity that a Qualified Scheduling Entity (QSE) is obligated to deliver to ERCOT, by hour and service type, from Resources represented by the QSE.

[NPRR1149: Replace the above definition "Ancillary Service Supply Responsibility" with the following upon system implementation:]

Ancillary Service Supply Responsibility

The net amount of Ancillary Service capacity that a Qualified Scheduling Entity (QSE) is obligated to deliver to ERCOT, by hour and service type.

[NPRR1013: Delete the above definition "Ancillary Service Supply Responsibility" upon system implementation of the Real-Time Co-Optimization (RTC) project.]

Ancillary Service Trade

A QSE-to-QSE transaction that transfers an obligation to provide Ancillary Service capacity between a buyer and a seller.

Applicable Legal Authority (ALA)

A Texas or federal law, rule, regulation, or applicable ruling of the PUCT or any other regulatory authority having jurisdiction, an order of a court of competent jurisdiction, or a rule, regulation, applicable ruling, procedure, protocol, guide or guideline of the Independent Organization, or any Entity authorized by the Independent Organization to perform registration or settlement functions.

Area Control Error (ACE)

A calculation of the MW correction needed to control the actual system frequency to the scheduled system frequency.

Authorized Representative

The person(s) designated by an Entity during the registration process in Section 16, Registration and Qualification of Market Participants, who is responsible for authorizing all registration information required by ERCOT Protocols and ERCOT business processes, including any changes in the future, and will be the contact person(s) between the registered Entity and ERCOT for all business matters requiring authorization by ERCOT.

Automatic Voltage Regulator (AVR)

A device on a Generation Resource or a control system at the Facility of a Generation Resource used to automatically control the voltage to an established Voltage Set Point.

[NPRR989: Replace the above definition "Automatic Voltage Regulator (AVR)" with the following upon system implementation:]

Automatic Voltage Regulator (AVR)

A device on a Generation Resource or a control system at the Facility of a Generation Resource or Energy Storage Resource (ESR) used to automatically control the voltage to an established Voltage Set Point.

Availability Plan

An hourly representation of availability of Reliability Must-Run (RMR) Units or an hourly representation of the capability of Black Start Resources as submitted to ERCOT by 0600 in the Day-Ahead by Qualified Scheduling Entities (QSEs) representing RMR Units or Black Start Resources. An hourly representation of availability of Firm Fuel Supply Service Resources (FFSSRs) as submitted to ERCOT 14 days prior to the Operating Day by QSEs representing FFSSRs.

[NPRR885: Replace the above definition "Availability Plan" with the following upon system implementation:]

Availability Plan

An hourly representation of availability of Reliability Must-Run (RMR) Units, Must-Run Alternatives (MRAs), or an hourly representation of the capability of Black Start Resources as submitted to ERCOT by 0600 in the Day-Ahead by Qualified Scheduling Entities (QSEs) representing RMR Units, MRAs, or Black Start Resources. An hourly representation of availability of Firm Fuel Supply Service Resources (FFSSRs) as submitted to ERCOT 14 days prior to the Operating Day by QSEs representing FFSSRs.

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Bank Business Day (*see* Business Day)

Bankrupt

The condition of an Entity that:

(a) Files a petition or otherwise commences a proceeding under any bankruptcy, insolvency, reorganization or similar law, or has any such petition filed or commenced against it;

(b) Makes an assignment or any general arrangement for the benefit of creditors;

(c) Has a liquidator, administrator, receiver, trustee, conservator, or similar official appointed with respect to it or any substantial portion of its property or assets; or

(d) Is generally unable to pay its debts as they fall due.

Base Point

The MW output level for a Resource produced by the Security-Constrained Economic Dispatch (SCED) process.

Black Start Resource (*see* Resource Attribute)

Black Start Service (BSS)

An Ancillary Service provided by a Resource able to start without support of the ERCOT Transmission Grid.

Black Start Service (BSS) Back-up Fuel

Fuel that is stored on site at the location of a Black Start Resource and that is available at all times and contracted with ERCOT for the purpose of powering the Resource when following ERCOT or the local Transmission Operator (TO) instruction to start without support of the ERCOT Transmission Grid in response to a Blackout or Partial Blackout.

Blackout

A condition in which frequency for the entire ERCOT System has dropped to zero and Generation Resources are no longer serving Load.

Partial Blackout

A condition in which an uncontrolled separation of a portion of the ERCOT System occurs and frequency for that portion has dropped to zero and Generation Resources within that portion are no longer serving Load and restoration is dependent on either internal Black Start Plans or assistance for restoration is needed from neighboring Transmission Operator(s) (TO(s)) within the ERCOT System which requires ERCOT coordination.

Block Load Transfer (BLT)

A transfer system that isolates a group of Loads from the Control Area in which they normally are served and then connects them to another Control Area. Such transfer systems involve either transferring Loads normally in the ERCOT Control Area to a non-ERCOT Control Area or transferring Loads normally in non-ERCOT Control Areas to the ERCOT Control Area.

Bus Load Forecast

A set of processes used by ERCOT to determine a forecast of the Load at each Electrical Bus in the ERCOT Transmission Grid.

Business Day

Monday through Friday, excluding observed holidays listed below:

(a) New Year's Day;

(b) Martin Luther King, Jr. Day;

(c) Memorial Day;

(d) Independence Day;

(e) Labor Day;

(f) Thanksgiving Thursday and Friday; and

(g) Two days at Christmas, as designated from time to time by the ERCOT CEO.

Bank Business Day

Any day during which the United States Federal Reserve Bank of New York is open for normal business activity.

Retail Business Day

Same as a Business Day, except in the case of retail transactions processed by a TSP or Distribution Service Provider (DSP), Competitive Retailers (CRs) shall substitute the TSP or DSP holidays for ERCOT holidays when determining the time available to the TSP or DSP to process the transaction. For additional important information related to Retail Business Days, please refer to the Retail Market Guide.

Business Hours

0800 to 1700 Central Prevailing Time (CPT) on Business Days.

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Capacity Trade

A QSE-to-QSE financial transaction that transfers responsibility to supply capacity between a buyer and a seller at a Settlement Point.

Cash Collateral

A Counter-Party's cash funds held by ERCOT to satisfy ERCOT creditworthiness requirements, as described in paragraph (d) of Section 16.11.3, Alternative Means of Satisfying ERCOT Creditworthiness Requirements.

Central Prevailing Time (CPT)

Either Central Standard Time or Central Daylight Time, in effect in Austin, Texas.

Comision Federal de Electricidad (CFE)

The government agency in Mexico charged with the responsibility of operating the Mexican national electricity grid.

Commercial Operations Date

The date on which an Interconnecting Entity (IE) or a Resource Entity expects that construction and trial operation of a Resource will be completed and the Resource is expected to complete the Resource interconnection process and be approved for participation in ERCOT market operations.

Common Information Model (CIM)

A standard way to communicate information about a transmission system. The CIM is used to describe the ERCOT transmission system topology consisting of Transmission Elements, including all the parameters needed to describe the Transmission Elements and how they interrelate to one another. The CIM that ERCOT and the TSP use must conform to the North American Electric Reliability Corporation (NERC) and Electric Power Research Institute (EPRI) standards for CIMs.

[NPRR857: Replace the above definition "Common Information Model (CIM)" 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:]

Common Information Model (CIM)

A standard way to communicate information about a transmission system. The CIM is used to describe the ERCOT transmission system topology consisting of Transmission Elements, including all the parameters needed to describe the Transmission Elements and how they interrelate to one another. The CIM that ERCOT and Market Participants use must conform to the North American Electric Reliability Corporation (NERC) and Electric Power Research Institute (EPRI) standards for CIMs.

Competitive Constraint

A contingency and limiting Transmission Element pair or group of Transmission Elements associated with a Generic Transmission Constraint (GTC) that is determined to be competitive using the process defined in Section 3.19, Constraint Competitiveness Tests.

Competitive Retailer (CR)

A Municipally Owned Utility (MOU) or an Electric Cooperative (EC) that offers Customer Choice and sells electric energy at retail in the restructured electric power market in Texas, or a Retail Electric Provider (REP).

Competitive Retailer (CR) of Record

The CR assigned to the Electric Service Identifier (ESI ID) in ERCOT's database. There can be no more than one CR of Record assigned to an ESI ID for any given time period.

Compliance Period

A calendar year beginning January 1 and ending December 31 in which Renewable Energy Credits (RECs) are required of a Retail Entity.

Compliance Premium

A payment awarded by the Program Administrator in conjunction with a REC that is generated by a renewable energy source that is not powered by wind and meets the criteria of subsection (l)

of P.U.C. SUBST. R. 25.173, Goal for Renewable Energy. For the purpose of the Renewable Portfolio Standard (RPS) requirements, one Compliance Premium is equal to one REC.

Conductor/Transformer 2-Hour Rating (*see* Rating)

Congestion Revenue Right (CRR)

A financial instrument that entitles the holder to be charged or to receive compensation (*i.e.*, congestion rent), depending on the instrument, when the ERCOT Transmission Grid is congested in the DAM or in Real-Time.

Flowgate Right (FGR)

A type of CRR that entitles the holder to receive compensation and is evaluated in each CRR Auction and DAM as the positive power flows represented by the quantity of the CRR bid or offer (MW) on a flowgate (i.e., predefined directional network element or a predefined bundle of directional network elements).

Point-to-Point (PTP) Obligation

A type of CRR that entitles the holder to be charged or to receive compensation and is evaluated in each CRR Auction and DAM as the positive and negative power flows on all directional network elements created by the injection and withdrawal at the specified source and sink points of the quantity represented by the CRR bid or offer (MW).

Point-to-Point (PTP) Obligation with Links to an Option

A type of CRR that entitles a Non-Opt-In Entity's (NOIE's) PTP Obligation bought in the DAM to be reflective of the NOIE's PTP Option. To qualify as a PTP Obligation of this type, the source and sink pairs on both the NOIE's PTP Obligation and the NOIE's PTP Option shall be the same, and the MWs of the NOIE's PTP Obligations shall be less than or equal to the number of MWs of the NOIE's PTP Option. Qualified PTP Obligations with Links to an Option shall be settled as if they were a PTP Option.

Point-to-Point (PTP) Option

A type of CRR that is evaluated in each CRR Auction and DAM as the positive power flows on all directional network elements created by the injection and withdrawal at the specified source and sink points in the quantity represented by the CRR bid or offer (MW), excluding all negative flows on all directional network elements. A PTP Option entitles the holder to receive compensation equal to the positive energy price difference between the sink and the source Settlement Point Prices. A PTP Option with Refund is evaluated in the same manner and compensated as described in Section 7.4.2, PCRR Allocations and Nominations.

Congestion Revenue Right (CRR) Account Holder

An Entity that is qualified to become the owner of record of CRRs and is registered as a CRR Account Holder with ERCOT.

Participating Congestion Revenue Right (CRR) Account Holder

For a given CRR Auction, a CRR Account Holder who either owns one or more CRRs effective during the Operating Days covered by the CRR Auction, or whose Counter-Party has a non-zero credit limit available and allocated to the CRR Auction as described in paragraph (1) of Section 7.5.5.3, Auction Process.

Congestion Revenue Right (CRR) Auction

A periodic auction by ERCOT that allows eligible CRR Account Holders to buy and sell CRRs.

Congestion Revenue Right (CRR) Auction Capacity

The fraction of the network capacity that is offered for sale in a given CRR Auction.

Congestion Revenue Right (CRR) First Offering

The CRR Auction, which is part of a CRR Long-Term Auction Sequence, in which a series of calendar months of CRRs is offered for sale for the first time.

Congestion Revenue Right (CRR) Long-Term Auction Sequence

A series of six CRR Auctions held consecutively, each of which entails the sale of a six-month window of CRRs.

Congestion Revenue Right (CRR) Monthly Auction

The CRR Auction in which a calendar month is offered for sale for the last time. This CRR Auction may, but is not required to, be conducted on the same dates as a CRR Auction that is part of a CRR Long-Term Auction Sequence.

Congestion Revenue Right (CRR) Network Model

A model of ERCOT network topology to be used in conducting a CRR Auction. It must be based on, but is not the same as, the Updated Network Model, as detailed in Section 3.10.3, CRR Network Model.

Congestion Revenue Right (CRR) Owner

A CRR Account Holder that owns one or more CRRs.

Constant Frequency Control (CFC)

An operating mode of an Automatic Generation Control (AGC) system. While in CFC, an AGC system will monitor only the frequency error to determine Resource adjustments needed to balance sources and obligations. CFC controls generation to increase or decrease by the amount of frequency deviation multiplied by the bias.

Constraint Management Plan (CMP)

A set of pre-defined manual transmission system actions, or automatic transmission system actions that do not constitute a Remedial Action Scheme (RAS), which are executed in response to system conditions to prevent or to resolve one or more thermal or non-thermal transmission security violations or to optimize the transmission system. CMPs may be developed in cases where studies indicate economic dispatch alone may be unable to resolve a transmission security violation or in response to Real-Time conditions where Security-Constrained Economic Dispatch (SCED) is unable to resolve a transmission security violation. ERCOT will employ CMPs to facilitate the market use of the ERCOT Transmission Grid, while maintaining system security and reliability in accordance with the Protocols, Operating Guides and North American Electric Reliability Corporation (NERC) Reliability Standards. CMPs are intended to supplement, not to replace, the use of SCED for prevention or resolution of one or more thermal or non-thermal transmission security violations. CMPs include, but are not limited to the following:

Automatic Mitigation Plan (AMP)

A set of pre-defined automatic actions to execute post-contingency to address voltage issues or reduce overloading on one or more given, monitored Transmission Facilities to below their Emergency Rating, excluding any set of automatic actions that constitute a Remedial Action Scheme. AMPs shall only include schemes which switch series reactors by monitoring quantities that are solely located at the same substation as the switched device. AMPs shall not include adjusting or tripping generation or Load shedding and shall not be implemented on Interconnection Reliability Operating Limits (IROLs).

Mitigation Plan

A set of pre-defined manual actions to execute post-contingency to address voltage issues or reduce overloading on one or more given, monitored Transmission Facilities to below their Emergency Rating with restoration of normal operating conditions within two hours. A Mitigation Plan must be implementable and may include transmission switching and Load shedding. Mitigation Plans shall not be used to manage constraints in Security-Constrained Economic Dispatch (SCED).

Pre-Contingency Action Plan (PCAP)

A set of pre-defined manual actions to execute pre-contingency to address voltage issues or reduce overloading on one or more given, monitored Transmission Facilities to below their Emergency Rating with restoration of normal operating conditions within two hours. A PCAP may include transmission switching and does not include Load shedding. A PCAP may also be implemented for the duration of an Outage and shall be included in the Outage Scheduler as soon as practicable.

Remedial Action Plan (RAP)

A set of pre-defined manual actions to execute post-contingency to address voltage issues or in order to reduce loading on one or more given, monitored Transmission Facilities to below their Emergency Rating within 15 minutes. RAPs are sufficiently dependable to assume they can be executed without loss of reliability to the interconnected network, with restoration of normal operating conditions and below Normal Rating within two hours as defined in the Network Operations Model. RAPs may be relied upon in allowing additional use of the transmission system in Security-Constrained Economic Dispatch (SCED). RAPs shall not include generation re-Dispatch or Load shedding.

Temporary Outage Action Plan (TOAP)

A temporary set of pre-defined manual actions to execute post-contingency, during a specified Transmission Facility or Resource Outage, in order to address voltage issues or reduce overloading on one or more given, monitored Transmission Facilities to below their Emergency Rating with restoration of normal operating conditions within two hours. A TOAP must be implementable and may include transmission switching and/or Load shedding. TOAPs shall not be used to manage constraints in Security-Constrained Economic Dispatch (SCED).

Continuous Service Agreement (CSA)

An arrangement between the owner or controller of a leased Premise and a CR wherein the CR provides service to the leased Premise between tenants so that the Premise does not experience discontinuation of electric service during vacancy.

Control Area

An electrical system, bound by interconnect (tie line) metering and telemetry, that continuously regulates, through automatic Resource control, its Resource(s) and interchange schedules to match its system Load and frequency schedule.

Control Area Operator (CAO)

An individual or set of individuals responsible for monitoring and controlling operation of a Control Area.

Controllable Load Resource (*see* Resource)

Controllable Load Resource Desired Load

The MW consumption for a Controllable Load Resource produced by summing its Scheduled Power Consumption and Ancillary Service deployments.

[NPRR1013: Delete the above definition "Controllable Load Resource Desired Load" upon system implementation of the Real-Time Co-Optimization (RTC) project.]

Cost Allocation Zone

One of the four zones in effect during the 2003 ERCOT market as they are changed pursuant to Section 3.4.2, Load Zone Modifications. A Cost Allocation Zone may be used by ERCOT to uplift certain costs to a QSE's Load regardless of NOIE Load Zone.

Counter-Party

A single Entity that is a QSE and/or a CRR Account Holder. A Counter-Party includes all registrations as a QSE, all subordinate QSEs, and all CRR Account Holders by the same Entity.

Credible Single Contingency

(1) The Forced Outage of any single Transmission Facility or, during a single fault, the Forced Outage of multiple Transmission Facilities (single fault multiple element);

(2) The Forced Outage of a double-circuit transmission line in excess of 0.5 miles in length;

(3) The Forced Outage of any single Generation Resource, and in the case of a Combined Cycle Train, the Forced Outage of the combustion turbine and the steam turbine if they cannot operate separately as provided in the Resource registration process; or

(4) For transmission planning purposes, contingencies are defined in the Planning Guide.

Critical Load

A Load that is designated as, or has a pending application to be designated as, a Critical Load Public Safety Customer, Critical Load Industrial Customer, Chronic Condition Residential

Customer, or Critical Care Residential Customer pursuant to P.U.C. SUBST. R. 25.497, Critical Load Industrial Customers, Critical Load Public Safety Customers, Critical Care Residential Customers, and Chronic Condition Residential Customers, or as a critical load under any other category identified under Public Utility Commission of Texas (PUCT) Rules.

Current Operating Plan (COP)

A plan by a Qualified Scheduling Entity (QSE) reflecting anticipated operating conditions for each of the Resources that it represents for each hour in the next seven Operating Days, including Resource operational data, Resource Status, and Ancillary Service Schedule.

[NPRR1013: Replace the definition "Current Operating Plan (COP)" above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

Current Operating Plan (COP)

A plan by a Qualified Scheduling Entity (QSE) reflecting anticipated operating conditions for each of the Resources that it represents for each hour in the next seven Operating Days, including Resource operational data, Resource Status, and Ancillary Service capabilities.

Current Operating Plan (COP) and Trades Snapshot

A record of a QSE's Capacity Trades, Energy Trades, and most recent COP.

[NPRR1013: Delete the above definition "Current Operating Plan (COP) and Trades Snapshot" upon system implementation of the Real-Time Co-Optimization (RTC) project.]

Customer

An Entity that purchases electricity for its consumption.

Customer Choice

The freedom of a retail Customer to purchase electric services, either individually or on an aggregated basis with other retail Customers, from the provider or providers of the Customer's choice and to choose among various fuel types, energy efficiency programs, and renewable power suppliers.

Customer Registration Database

The database maintained by the registration agent containing information identifying each Premise, including current and previous CRs serving the Premise.

Cybersecurity Contact

The person, desk, or hotline designated by an Entity, as set forth in Section 16, Registration and Qualification of Market Participants, that is the primary point of contact for communications between the registered Entity and ERCOT with respect to Cybersecurity Incidents. A Market Participant may designate a temporary Cybersecurity Contact for a particular Cybersecurity Incident pursuant to Section 16.19, Cybersecurity Incident Notification.

Cybersecurity Incident

A malicious or suspicious act that compromises or disrupts a computer network or system that could foreseeably jeopardize the reliability or integrity of the ERCOT System or ERCOT's ability to perform the functions of an independent organization under the Public Utility Regulatory Act (PURA).

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Data Agent-Only Qualified Scheduling Entity (QSE) (*see* Qualified Scheduling Entity (QSE))

Data Aggregation

The process of netting, grouping, and summing Load consumption data, applying appropriate profiles, Transmission Loss Factors (TLFs), and Distribution Loss Factors (DLFs) and calculating and allocating UFE to determine each QSE and/or Load Serving Entity's (LSE's) responsibility by Settlement Interval by Load Zone and by other prescribed aggregation determinants.

Data Aggregation System (DAS)

The database and communication system that collects meter data from TSPs, DSPs and ERCOT Polled Settlement (EPS) Meters. The system performs aggregation functions to Load data in order to satisfy certain objectives, such as providing TSPs with Load share data to use in billing CRs, assigning QSE Load responsibility, and assisting CRs and QSEs in their Settlement responsibilities. The data is also compiled along Load and Weather Zones.

Data Archive

An integrated normalized data structure of all the target source systems' transactions. The population of the Data Archive is an extraction of data from the transaction systems without altering the data. The Data Archive is used to populate the Data Warehouse.

Data Warehouse

De-normalized data stored in a schema, physically optimized to handle high volumes of data and concurrent user access, and generally lightly indexed.

Day-Ahead

The 24-hour period before the start of the Operating Day.

Day-Ahead Market (DAM)

A daily, co-optimized market in the Day-Ahead for Ancillary Service capacity, certain CRRs, and forward financial energy transactions.

Day-Ahead Market (DAM)-Committed Interval

A Settlement Interval for which the Resource has been committed due to a DAM award.

Day-Ahead Market (DAM) Energy Bid

A proposal to buy energy in the DAM at a Settlement Point at a monotonically decreasing price with increasing quantity.

Day-Ahead Market (DAM) Energy-Only Offer

A QSE's willingness to sell energy at or above a certain price and at a certain quantity at a specific Settlement Point in the DAM. A DAM Energy-Only Offer Curve may be offered only in the DAM. DAM Energy-Only Offer Curves are not Resource-specific.

Day-Ahead Market (DAM) Resettlement Statement (*see* Settlement Statement)

Day-Ahead Market (DAM) Statement (*see* Settlement Statement)

Day-Ahead Operations

The Day-Ahead process consisting of the DAM and Day-Ahead Reliability Unit Commitment (DRUC).

Day-Ahead Reliability Unit Commitment (DRUC)

A Reliability Unit Commitment (RUC) process performed for the next Operating Day.

[NPRR1013: Insert the following definition "Day-Ahead System-Wide Offer Cap (DASWCAP)" upon system implementation of the Real-Time Co-Optimization (RTC) project:]

Day-Ahead System-Wide Offer Cap (DASWCAP)

The DASWCAP shall be determined in accordance with Public Utility Commission of Texas (PUCT) Substantive Rules.

Delivery Plan

A plan by ERCOT containing the hours and levels of operation that a Reliability Must-Run (RMR) Unit is instructed to operate.

Demand

The amount of instantaneous electric power in MW delivered at any specified point or points on a system.

Designated Representative

A responsible natural person authorized by an Entity to register with ERCOT as a Renewable Energy Credit (REC) Account Holder or manage an REC Account.

Digital Certificate

An electronic file installed on a programmatic interface or an individual's assigned computer used to authenticate that the interface or individual is authorized for secure electronic messaging with ERCOT's computer systems.

Direct Current Tie (DC Tie)

Any non-synchronous transmission interconnections between ERCOT and non-ERCOT electric power systems.

Direct Current Tie (DC Tie) Curtailment Notice

A notification issued by ERCOT indicating the need for curtailment of DC Tie import or export schedules due to current system conditions.

Direct Current Tie (DC Tie) Load

A Load used to represent the withdrawal of power from the ERCOT System to a DC Tie.

[NPRR857: Insert the following definition "Direct Current Tie Operator (DCTO)" 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:]

Direct Current Tie Operator (DCTO)

An Entity that operates a Direct Current Tie (DC Tie) interconnected to the ERCOT System and that is registered as a DCTO.

Direct Current Tie (DC Tie) Resource

A Resource used to represent the injection of power into the ERCOT System from a DC Tie.

Direct Current Tie (DC Tie) Schedule

An energy schedule between ERCOT and a non-ERCOT Control Area and is represented by a corresponding Electronic Tag (e-Tag) that contains the physical transaction information such as the Settlement Point energy amount (MW), the associated DC Tie, and the buyer and seller.

Direct Load Control (DLC)

The control of end-use equipment (e.g., air conditioning equipment, water heaters) to reduce or increase energy consumption during select periods.

Dispatch

The act of issuing Dispatch Instructions.

Dispatch Instruction

A specific command issued by ERCOT to a Qualified Scheduling Entity (QSE), Transmission Service Provider (TSP), or Distribution Service Provider (DSP) in the operation of the ERCOT System.

[NPRR857: Replace the above definition "Dispatch Instruction" 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:]

Dispatch Instruction

A specific command issued by ERCOT to a Qualified Scheduling Entity (QSE), Transmission Service Provider (TSP), Direct Current Tie Operator (DCTO), or Distribution Service Provider (DSP) in the operation of the ERCOT System.

Dispute Contact

The individual associated with a Market Participant who is the primary contact with ERCOT regarding the pursuit of an Alternative Dispute Resolution (ADR) request.

Distributed Generation (DG)

An electrical generating facility located at a Customer's point of delivery (point of common coupling) ten megawatts (MW) or less and connected at a voltage less than or equal to 60 kilovolts (kV) which may be connected in parallel operation to the utility system.

Distributed Renewable Generation (DRG)

Electric generation with a capacity of not more than 2,000 kW provided by a renewable energy technology that is installed on a retail electric Customer's side of the meter.

Distribution Generation Resource (*see* Resource)

Distribution Loss Factor (DLF)

The ratio of a DSP's estimated Distribution Losses to the total amount of energy deemed consumed (Interval Data Recorder (IDR) plus profiled consumption) on the DSP's system.

Distribution Losses

The difference between the energy delivered to the Distribution System and the energy consumed by Customers connected to the Distribution System.

Distribution Service Provider (DSP)

An Entity that owns or operates a Distribution System for the delivery of energy from the ERCOT Transmission Grid to Customers.

Distribution System

That portion of an electric delivery system operating under 60 kV that provides electric service to Customers or Wholesale Customers.

DUNS Number

A unique nine-digit common company identifier used in electronic commerce transactions, supplied by the Data Universal Numbering System (DUNS).

Dynamic Rating

The current-carrying capability of a Transmission Element adjusted to take into account the effect of ambient weather conditions.

Dynamic Rating Processor

A process used to establish ERCOT Transmission Element limits based upon factors such as ambient temperature and wind speed.

Dynamically Scheduled Resource (DSR) (*see* Resource Attribute)

Dynamically Scheduled Resource (DSR) Load

A Load that a QSE designates to be followed by a Dynamically Scheduled Resource (DSR).

[NPRR1000: Delete the definition "Dynamically Scheduled Resource (DSR) Load" above upon system implementation.]

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Electric Cooperative (EC)

(a) A corporation organized under the Electric Cooperative Corporation Act, TEX. UTIL. CODE ANN. ch 161 (Vernon 1998 & Supp. 2007);

(b) A corporation organized as an electric cooperative in a state other than Texas that has obtained a certificate of authority to conduct business in Texas; or

(c) A successor to an electric cooperative created before June 1, 1999 under a conversion plan approved by a vote of the members of the electric cooperative, regardless of whether the successor later purchases, acquires, merges with, or consolidates with other electric cooperatives.

Electric Reliability Council of Texas, Inc. (ERCOT)

A Texas nonprofit corporation that has been certified by the PUCT as the Independent Organization for the ERCOT Region.

Electric Reliability Organization

The organization approved by the Federal Energy Regulatory Commission (FERC) to perform the electric reliability organization functions described in the Electricity Modernization Act of 2005, 16 U.S.C. § 824o (2005).

Electric Service Identifier (ESI ID)

The basic identifier assigned to each Service Delivery Point used in the registration and settlement systems managed by ERCOT or another Independent Organization.

Electrical Bus

(1) A physical transmission element defined in the Network Operations Model that connects, using breakers and switches, one or more:

(a) Loads;

(b) Lines;

(c) Transformers;

(d) Generators;

(e) Capacitors;

(f) Reactors;

(g) Phase shifters; or

(h) Other reactive control devices to the ERCOT Transmission Grid where there is negligible impedance between the connected Transmission Elements.

(2) All Electrical Buses are designated by ERCOT and Transmission Service Providers (TSPs) for modeling the electrical topology of the ERCOT Transmission Grid.

[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) All Electrical Buses are designated by ERCOT and Market Participants for modeling the electrical topology of the ERCOT Transmission Grid.

Resource Connectivity Node

The Electrical Bus to which the terminal of a Resource is connected.

Electrically Similar Settlement Points

Two or more distinct Settlement Points that are either mapped to the same electrical location in a market model or are mapped to locations that are connected by a transmission element with a reactance of less than 0.0005 per unit.

Eligible Transmission Service Customer

A Transmission and/or Distribution Service Provider (TDSP) (for all uses of its transmission system), or any electric utility, MOU, EC, power generation company, CR, REP, federal power marketing agency, exempt wholesale generator, Qualifying Facility (QF), Independent Power

Marketer, or other Entity that the PUCT has determined to be an Eligible Transmission Service Customer.

Emergency Base Point

The target MW output level for a Resource that is selected by ERCOT during an Emergency Condition or Watch.

Emergency Condition

An operating condition in which the safety or reliability of the ERCOT System is compromised or threatened, as determined by ERCOT.

Emergency Notice

The communication issued by ERCOT to declare that ERCOT is operating in an Emergency Condition.

Emergency Ramp Rate

The maximum rate of change (up and down) in MW per minute of a Resource to provide Responsive Reserve (RRS) that is deployed by ERCOT and that is provided to ERCOT in up to ten segments, each represented by a single MW per minute value (across the capacity of the Resource), which describes the available rate of change for the given range (between High Sustained Limit (HSL) and Low Sustained Limit (LSL)) of the generation or consumption of a Resource. In Real-Time Security-Constrained Economic Dispatch (SCED) Dispatch, the up and down Emergency Ramp Rates are telemetered by the Qualified Scheduling Entity (QSE) to ERCOT and represent the total capacity (in MW) that the Resource can change from its current actual generation or consumption within the next five minutes divided by five.

[NPRR863 and NPRR1013: Replace the above definition "Emergency Ramp Rate" with the following upon system implementation of NPRR863; or upon system implementation of the Real-Time Co-Optimization (RTC) project, respectively:]

Emergency Ramp Rate

The maximum rate of change (up and down) in MW per minute of a Resource to provide energy during Emergency Conditions that is provided to ERCOT in up to ten segments, each represented by a single MW per minute value (across the capacity of the Resource), which describes the available rate of change for the given range (between High Sustained Limit (HSL) and Low Sustained Limit (LSL)) of the generation or consumption of a Resource. In Real-Time Security-Constrained Economic Dispatch (SCED) Dispatch, the up and down Emergency Ramp Rates are telemetered by the Qualified Scheduling Entity (QSE) to ERCOT

and represent the total capacity (in MW) that the Resource can change from its current actual generation or consumption within the next five minutes divided by five.

Emergency Rating (*see* Rating)

Emergency Response Service (ERS)

An emergency service consistent with P.U.C. SUBST. R. 25.507, Electric Reliability Council of Texas (ERCOT) Emergency Response Service (ERS), to be deployed by ERCOT to help prevent or alleviate an actual or anticipated Energy Emergency Alert (EEA) event. ERS is not an Ancillary Service.

ERS-10

ERS with a ten-minute ramp period.

ERS-30

ERS with a 30-minute ramp period.

Non-Weather-Sensitive ERS

A type of ERS in which an ERS Resource may participate in ERS without meeting the qualification requirements for weather sensitivity set forth in paragraph (5) of Section 3.14.3.1, Emergency Response Service Procurement.

Weather-Sensitive ERS

A type of ERS in which an ERS Load may participate in ERS only after meeting the qualification requirements for weather sensitivity set forth in paragraph (5) of Section 3.14.3.1.

Emergency Response Service (ERS) Contract Period

A period designated by ERCOT during which an ERS Resource is obligated to provide ERS consisting of all or part of the contiguous hours in an ERS Standard Contract Term.

Emergency Response Service (ERS) Generator

Either (1) an individual generator contracted to provide ERS which is not a Generation Resource or a source of intermittent renewable generation and which provides ERS by injecting energy to the ERCOT System, or (2) an aggregation of such generators.

Emergency Response Service (ERS) Load

A Load or aggregation of Loads contracted to provide ERS.

Emergency Response Service (ERS) Resource

Either an ERS Load or an ERS Generator.

Emergency Response Service (ERS) Self-Provision

The designation by a QSE of one or more ERS Resources to meet some or all of that QSE's Load Ratio Share (LRS) of the total ERCOT-wide cost of ERS.

Emergency Response Service (ERS) Standard Contract Term

One of four periods for which ERCOT may procure ERS.

Emergency Response Service (ERS) Time Period

Blocks of hours in an ERS Standard Contract Term in which ERS Resources are contractually committed to provide ERS.

[NPRR1014: Insert the following definition "Energy Bid/Offer Curve" upon system implementation:]

Energy Bid/Offer Curve

A proposal from an Energy Storage Resource (ESR) to buy and sell energy at a Settlement Point in the form of a single monotonically non-decreasing price curve that covers both the charging and discharging MW range and provides a bid price for charging and an offer price for discharging.