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| NPRR Number | [1317](https://www.ercot.com/mktrules/issues/NPRR1317) | NPRR Title | Creation of Non-Settled Generator (NSG) and Clarification of the Types, Usage, and Registration of Distributed Generation |
| Date Posted | | December 19, 2025 | |
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| Requested Resolution | | Normal | |
| Nodal Protocol Sections Requiring Revision | | 1.6, Open Access to the ERCOT Transmission Grid  1.6.5, Interconnection of New or Existing Generation  2.1, Definitions  2.2, Acronyms and Abbreviations  3.1.4.3, Reporting for Planned Outages, Maintenance Outages, and Rescheduled Outages of Resource and Transmission Facilities  3.1.5.1, ERCOT Evaluation of Planned Outage and Maintenance Outage of Transmission Facilities  3.6.2, Decision Making Entity for a Resource  3.8.1, Split Generation Resources  3.8.7, Self-Limiting Facility  3.8.9, Interconnection of a Non-Settled Generator (new)  3.10.7.2, Modeling of Resources and Transmission Loads  3.14.1, Reliability Must Run  3.14.1.8, RMR and/or MRA Contract Extension  3.14.1.9, Generation Resource/Energy Storage Resource Status Updates  3.14.1.10, Eligible Costs  3.14.1.19, Charge for Contributed Capital Expenditures  3.14.4.1, Overview and Description of MRAs  3.15, Voltage Support  6.5.5.2, Operational Data Requirements  10.2.2, TSP and DSP Metered Entities  10.2.3, ERCOT-Polled Settlement Meters  10.3.2.1, Generation Resource Meter Splitting  16.5, Registration of a Resource Entity  16.5.1, Technical and Managerial Requirements for Resource Entity Applicants  16.5.1.1, Designation of a Qualified Scheduling Entity  16.5.2, Registration Process for a Resource Entity  16.5.3, Changing QSE Designation  18.2, Methodology  23, Form C, Managed Capacity Declaration  23, Form U, NSG QSE Acknowledgement (new) | |
| Related Documents Requiring Revision/Related Revision Requests | | Planning Guide Revision Request (PGRR) 140, Related to NPRR1317, Creation of Non-Settled Generator (NSG) and Clarification of the Types, Usage, and Registration of Distributed Generation | |
| Revision Description | | This NPRR clarifies the term “Distributed Generation” (DG) and, introduces the categories of “Distributed Generation,” which include:   * Unregistered Distributed Generator; * Distribution Generation Resource; * Settlement Only Distribution Energy Storage System; * Settlement Only Distribution Generator; and * Non-Settled Distribution Generator.   This NPRR also clarifies the Resource registration process for Resource Entities. Additionally, this NPRR updates DG interconnection, registration, and reporting requirements to ensure consistency throughout the ERCOT System as it relates to DG. Specifically, this NPRR:   * Creates a new defined term “Non-Settled Generation” (NSG) along with its two subcategories “Non-Settled Distributed Generation” (NSDG), and “Non-Settled Transmission Generation” (NSTG); * Replaces the phrase “unregistered Distributed Generation” with the appropriate language throughout the Protocols; * Replaces DG with the appropriate language; * Creates new Section 3.8.9, which establishes interconnection requirements for an NSG; * Establishes new paragraph (22) of Section 6.5.5.2, which lists Real-Time telemetry information a QSE representing an owner of an NSG greater than 10 MW must provide to ERCOT; * Within paragraph (5) of Section 3.10.7.2, requires the owner of an NSDG to provide ERCOT, its interconnecting DSP, and the TSP that interconnects the DSP to the transmission system with information describing each of its NSDG facilities; * Modifies the definition of Resource Entity to clarify who is responsible for the Resource and in what capacity each Entity is responsible; and * Modifies Section 16.5 to explicitly require:   (1) An Entity that owns a Generation Resource, SOG, or Load Resource to ensure that the Entity or its agent register with ERCOT as a Resource Entity for a generator or Load;  (2) An Entity that owns a generator or load that comes within the definition of Generation Resource, SOG, or Load Resource DG to ensure that the generator or load is registered with ERCOT as a Generation Resource, SOG, or Load Resource as appropriate; and  (3) An Entity that owns any generation facility of 1 MW or greater to provide all required information on that facility as required by Section 3.10.7.2. | |
| Reason for Revision | | [Strategic Plan](https://www.ercot.com/files/docs/2023/08/25/ERCOT-Strategic-Plan-2024-2028.pdf) Objective 1 – Be an industry leader for grid reliability and resilience  [Strategic Plan](https://www.ercot.com/files/docs/2023/08/25/ERCOT-Strategic-Plan-2024-2028.pdf) Objective 2 - Enhance the ERCOT region’s economic competitiveness with respect to trends in wholesale power rates and retail electricity prices to consumers  [Strategic Plan](https://www.ercot.com/files/docs/2023/08/25/ERCOT-Strategic-Plan-2024-2028.pdf) Objective 3 - Advance ERCOT, Inc. as an independent leading industry expert and an employer of choice by fostering innovation, investing in our people, and emphasizing the importance of our mission  General system and/or process improvement(s)  Regulatory requirements  ERCOT Board/PUCT Directive  *(please select ONLY ONE – if more than one apply, please select the ONE that is most relevant)* | |
| Justification of Reason for Revision and Market Impacts | | The existing use of the term “Distributed Generation” (DG) is too broad and varies throughout the Protocols. This NPRR incorporates the Resource Definition Task Force’s (RTF’s) RTF-5 defined terms “Non-Settled Generation” (NSG) to clarify the appropriate use of DG or subtype of DG throughout the Protocols and meets the RTF’s objectives to “identify[] problematic terms” in the Protocols and “improv[e] the current structure and terms where practical.”  Furthermore, to clear up any confusion around who is responsible for acting in a certain manner throughout the Protocols, this NPRR clarifies that a Resource Entity is responsible for a Resource, including for making decisions regarding the Resource. The NPRR also clarifies that the rules and law concerning agency already apply to a Resource Entity and/or its agent. Therefore, language referring to a Resource Entity that “owns or controls” is redundant and has been removed throughout the Protocols. | |

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| **Market Rules Notes** |

Please note the following NPRR(s) also propose revisions to the following sections:

* NPRR1272, Voltage Support at Private Use Networks
  + Section 3.15
* NPRR1306, Removal of Digital Certificate References for Market Participants with ERCOT MIS Access
  + Section 23, Form C

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| Proposed Protocol Language Revision |

1.6 Interconnection to the ERCOT System

***1.6.5 Interconnection of New or Existing Generation***

(1) Interconnection of new Generation Resources, Energy Storage Resources (ESRs), or Settlement Only Generators (SOGs) to the ERCOT Transmission Grid must be in accordance with the Protocols, the Planning Guide, the Nodal Operating Guide and Other Binding Documents.

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| ***[NPRR995: Replace paragraph (1) above with the following upon system implementation:]***  (1) Interconnection of new Generation Resources, Energy Storage Resources (ESRs), Settlement Only Generators (SOGs), or Settlement Only Energy Storage Systems (SOESSs) to the ERCOT Transmission Grid must be in accordance with the Protocols, the Planning Guide, the Nodal Operating Guide and Other Binding Documents. |

(2) For existing Generation Resources, ESRs, and SOGs which connect to a new Point of Interconnection (POI) or which utilize more than one POI to the ERCOT Transmission Grid, any Protocol or Other Binding Document requirements applicable to Generation Resources, ESRs, and SOGs which are based upon the execution date of the Standard Generation Interconnection Agreement (SGIA) shall be applied to the date of the first executed SGIA with the following exceptions:

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| ***[NPRR995: Replace paragraph (2) above with the following upon system implementation:]***  (2) For existing Generation Resources, ESRs, SOGs, and SOESSs which connect to a new Point of Interconnection (POI) or which utilize more than one POI to the ERCOT Transmission Grid, any Protocol or Other Binding Document requirements applicable to Generation Resources, ESRs, SOGs, and SOESSs which are based upon the execution date of the Standard Generation Interconnection Agreement (SGIA) shall be applied to the date of the first executed SGIA with the following exceptions: |

(a) For a new POI, existing Generation Resources, ESRs, and Settlement Only Transmission Self-Generators (SOTSGs) shall comply with the requirements in Section 3.15, Voltage Support, and Nodal Operating Guide Section 2.9, Voltage Ride-Through Requirements for Generation Resources, based upon the execution date of the most recent SGIA.

(b) For more than one POI, existing Generation Resources, ESRs, and SOTSGs shall comply with the requirements in Section 3.15 and Nodal Operating Guide Section 2.9 based upon the execution date of the SGIA relative to the POI where the Generation Resource, ESR, or SOTSG is electrically connected.

(3)       When a Municipally Owned Utility (MOU) or Electric Cooperative (EC) transferring Load into the ERCOT System owns a generation unit currently serving the transferring Load in a non-ERCOT Control Area and seeks to interconnect the generation unit to the ERCOT Transmission Grid in conjunction with the Load transfer, the interconnection will be subject to the requirements in paragraph (1) above; however, if the Protocols, Planning Guide, Nodal Operating Guide or Other Binding Documents set forth an alternate requirement for Generation Resources, ESRs, or SOGs that were installed, connected, operating, or had an SGIA executed before a specified date, then ERCOT, in its sole discretion, may apply the alternate requirement to the MOU’s or EC’s generation unit, subject to the following:

(a) The generation unit must have been operating in the non-ERCOT Control Area on or before the date specified in the Protocol, Planning Guide, Nodal Operating Guide or Other Binding Document provision that sets forth the alternate requirement;

(b) The generation unit has not undergone a modification pursuant to paragraph (1)(c) of Planning Guide Section 5.2.1, Applicability, subsequent to the specified date from paragraph (3) above;

(c) The MOU or EC must submit a written request to ERCOT that identifies the alternate requirement(s) it seeks to have applied and explains why compliance with the requirement(s) applicable to new Generation Resources, ESRs, or SOGs is not feasible at a reasonable cost; and

(d) The MOU or EC must demonstrate to ERCOT’s satisfaction through interconnection or similar studies that allowing the generation unit to comply with the alternate requirement will not create a risk to the reliability of the ERCOT System.

(4) To initiate a new interconnection or maintain an existing interconnection to the ERCOT System, Distributed Generators (DGs) and Non-Settled Transmission Generators (NSTGs) must comply with all applicable requirements in the Protocols, the Planning Guide, the Nodal Operating Guide and Other Binding Documents.

## 2.1 DEFINITIONS

Distributed Generator (DG)

An electrical generator, including an Energy Storage System (ESS), that is connected, either (i) directly or (ii) indirectly, through the Distribution System to the ERCOT System, and that may be connected in parallel operation to the ERCOT System. DG includes the following categories:

(1) Unregistered Distributed Generator (UDG);

(2) Distribution Generation Resource (DGR);

(3) Settlement Only Distribution Energy Storage System (SODESS);

(4) Settlement Only Distribution Generator (SODG); and

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| (5) Non-Settled Distribution Generator (NSDG).***[NPRR1265: Replace the above definition “Distributed Generation (DG)” with the following upon system implementation:]***  **Distributed Generator (DG)**  An electrical generator, including an Energy Storage System (ESS), that is connected , either (i) directly or (ii) indirectly through the Distribution System to the ERCOT System, and that may be connected in parallel operation to the ERCOT System. DG includes the following:  ***Unregistered Distributed Generator (UDG)***  A generator with a nameplate capacity of one MW or less that is connected to the Distribution System, and which is not registered with ERCOT for the purpose of Settlement.  ***Distribution Generation Resource (DGR)***  ***Settlement Only Distribution Energy Storage System (SODESS)***  ***Settlement Only Distribution Generator (SODG)***  ***Non-Settled Distribution Generator (NSDG)*** |

Interconnecting Entity (IE)

An Entity that has submitted a Generation Interconnection or Change Request Application for a Generation Resource, Settlement Only Generator (SOG), or Non-Settled Generator (NSG) and meets the requirements of Planning Guide Section 5.2.1, Applicability.

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| ***[NPRR995: Replace the above definition “Interconnecting Entity (IE)” with the following upon system implementation:]***  **Interconnecting Entity (IE)**  An Entity that has submitted a Generation Interconnection or Change Request Application for a Generation Resource, Energy Storage Resource (ESR), Settlement Only Energy Storage System (SOESS), or Settlement Only Generator (SOG), or Non-Settled Generator (NSG) and meets the requirements of Planning Guide Section 5.2.1, Applicability. |

**Non-Settled Generator (NSG)**

A generator, including an Energy Storage System (ESS), with a nameplate capacity greater than one MW that is not registered with ERCOT as a Generation Resource, Settlement Only Generator (SOG), Energy Storage Resource (ESR), or Settlement Only Energy Storage System (SOESS). NSG exports to the ERCOT System are not entitled to Settlement and will not be used for Settlement purposes.

***Non-Settled Distribution Generator (NSDG)***

An NSG that is a Distributed Generator (DG).

***Non-Settled Transmission Generator (NSTG)***

An NSG that is either (i) directly or (ii) indirectly connected to the ERCOT Transmission Grid and that may be connected in parallel operation to the ERCOT System.

Qualified Scheduling Entity (QSE)

A Market Participant that is qualified by ERCOT in accordance with Section 16, Registration and Qualification of Market Participants, for communication with ERCOT for Resource Entities, owners of Non-Settled Generators (NSGs) that are greater than ten MW, or Load Serving Entities (LSEs) and for settling payments and charges with ERCOT.

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

A limited type of QSE that is registered with ERCOT pursuant to Section 16.2.1.2, Data Agent-Only Qualified Scheduling Entities, for the sole purpose of acting as an agent for a QSE that meets all the criteria of Section 16.2.1, Criteria for Qualification as a Qualified Scheduling Entity, relating to the exchange of certain communications and data over the ERCOT Wide Area Network (WAN), as provided in Nodal Operating Guide Section 7, Telemetry and Communication.

Master Qualified Scheduling Entity (QSE)

A QSE designated by Resource Entities owning or controlling a Generation Resource that has been split into two or more Split Generation Resources as set forth in Section 3.8.1, Split Generation Resources, that provides ERCOT data and dispatch on total Generation Resource basis in accordance with the Protocols.

**Resource**

The term is used to refer to an Energy Storage Resource (ESR), a Generation Resource, or a Load Resource. The term “Resource” used by itself in these Protocols does not include a Settlement Only Generator (SOG) , a Non-Settled Generator (NSG), or an Emergency Response Service (ERS) Resource.

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| ***[NPRR995: Replace the above definition “Resource” with the following upon system implementation:]***  **Resource**  The term is used to refer to an Energy Storage Resource (ESR), a Generation Resource, or a Load Resource. The term “Resource” used by itself in these Protocols does not include a Settlement Only Generator (SOG), Settlement Only Energy Storage System (SOESS), a Non-Settled Generator (NSG), or an Emergency Response Service (ERS) Resource. |

***Energy Storage Resource (ESR)***

An Energy Storage System (ESS) registered with ERCOT for the purpose of providing energy and/or Ancillary Service to the ERCOT System.

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| ***[NPRR1029: Insert the following definition “DC-Coupled Resource upon system implementation:]***  ***DC-Coupled Resource***  A type of Energy Storage Resource (ESR) in which an Energy Storage System (ESS) is combined with wind and/or solar generation in the same modeled generation station and interconnected at the same Point of Interconnection (POI), and where these technologies are interconnected within the site using direct current (DC) equipment. The combined technologies are then connected to the ERCOT System using the same direct current-to-alternating current (DC-to-AC) inverter(s). To be classified as a DC-Coupled Resource, the generator(s) and ESS(s) at a site must meet the following conditions:  (1) The ESS component of the Resource must have a nameplate rating of at least ten MW and ten MWh, or the MW rating must equal or exceed 50% of the nameplate MW rating of the inverter; and  (2) All intermittent renewable generators must meet the conditions for aggregation stated in paragraph (13) of Section 3.10.7.2, Modeling of Resources and Transmission Loads, except to the extent any such condition requires the generator to be a Resource. |

***Distribution Energy Storage Resource (DESR)***

An Energy Storage Resource (ESR) connected to the Distribution System that is either:

(1) Greater than ten MW and not classified as a Non-Settled Distribution Generator; or

(2) Greater than one MW that chooses to register as a Resource with ERCOT to participate in the ERCOT markets.

***Transmission Energy Storage Resource (TESR)***

An Energy Storage Resource (ESR) connected to the ERCOT transmission system that is either:

(1) Greater than ten MW and not registered with the Public Utility Commission of Texas (PUCT) as a self-generator; or

(2) Greater than one MW that chooses to register as a Resource with ERCOT to participate in the ERCOT markets.

***Generation Resource***

A generator with a nameplate capacity of one MW or greater that is capable of providing energy or Ancillary Service to the ERCOT System and is registered with ERCOT as a Generation Resource.

***Distribution Generation Resource (DGR)***

A Generation Resource connected to the Distribution System.

***Transmission Generation Resource (TGR)***

A Generation Resource connected to the ERCOT Transmission Grid.

***Load Resource***

A Load capable of providing Ancillary Service to the ERCOT System and/or energy in the form of Demand response and registered with ERCOT as a Load Resource.

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

A Controllable Load Resource that is an aggregation of individual metered sites, each of which has less than ten MW of Demand response capability and all of which are located within a single Load Zone.

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| ***[NPRR1188: Delete the above definition “Aggregate Load Resource (ALR)” upon system implementation.]*** |

***Controllable Load Resource***

A Load Resource capable of controllably reducing or increasing consumption under Dispatch control by ERCOT.

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| ***[NPRR1188: Insert the definition “Aggregate Load Resource (ALR)” below upon system implementation:]***  **Aggregate Load Resource (ALR)**  A Controllable Load Resource (CLR) that is an aggregation of individual metered sites, each of which has less than ten MW of Demand response capability and all of which are located within a single Load Zone. |

***Settlement Only Generator (SOG)***

A generator that is settled for exported energy only, but which may not participate in the Ancillary Services market, Reliability Unit Commitment (RUC), Security-Constrained Economic Dispatch (SCED), or make energy offers, and that is registered as a Settlement Only Generator (SOG). These units include:

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| ***[NPRR995: Delete the above definition “Settlement Only Generator (SOG)” upon system implementation.]*** |

***Settlement Only Transmission Generator (SOTG)***

An SOG that is connected to the ERCOT Transmission Grid with a nameplate capacity of at least one MW and no more than ten MW.

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| ***[NPRR995: Delete the above definition “Settlement Only Transmission Generator (SOTG)” upon system implementation.]*** |

***Settlement Only Transmission Self-Generator (SOTSG)***

An SOG that is connected to the ERCOT Transmission Grid with a nameplate capacity of one MW or more and whose owner is registered with the Public Utility Commission of Texas (PUCT) as a self-generator.

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| ***[NPRR995: Delete the above definition “Settlement Only Transmission Self-Generator (SOTSG)” upon system implementation.]*** |

Resource Entity

An Entity that owns or controls a Generation Resource, an Energy Storage Resource (ESR), a Settlement Only Generator (SOG), or a Load Resource and has been designated by an owner to register as the Resource Entity for that Generation Resource, ESR, SOG, or Load Resource for the purposes of these Protocols (or, in the case of a Split Generation Resource, a Resource Entity).

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| ***[NPRR995: Replace the above definition “Resource Entity” with the following upon system implementation:]***  **Resource Entity**  An Entity that owns or controls a Generation Resource, an Energy Storage Resource (ESR), a Settlement Only Generator (SOG), a Settlement Only Energy Storage System (SOESS), or a Load Resource and has been designated by an owner to register as the Resource Entity for that Generation Resource, ESR, SOG, SOESS, or Load Resource for the purposes of these Protocols (or, in the case of a Split Generation Resource, a Resource Entity). |

**Self-Limiting Facility**

A modeled generation station that includes one or more Generation Resources, Non-Settled Generators (NSGs), and/or Energy Storage Resources (ESRs) with an established limit on the total MW Injection that is less than the total nameplate capacity of all Resource(s) within the Facility. A Facility with one or more ESRs may also have an established limit on the MW Withdrawal that is less than the total nameplate MW Withdrawal rating of all ESR(s) within the facility.

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| ***[NPRR1077: Replace the above definition “Self-Limiting Facility” with the following upon system implementation:]***  **Self-Limiting Facility**  A modeled generation station that includes one or more Generation Resources, Energy Storage Resources (ESRs), Non-Settled Generators (NSGs), and/or Settlement Only Generators (SOGs) with an established limit on the total MW Injection that is less than the total nameplate capacity of all registered generators or Energy Storage Systems (ESSs) within the Facility. A Facility with one or more ESRs may also have an established limit on the MW Withdrawal that is less than the total nameplate MW Withdrawal rating of all ESRs within the facility. |

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| [NPRR995: Insert the following definitions “Settlement Only Energy Storage System (SOESS)”, “Settlement Only Distribution Energy Storage System (SODESS)”, and “Settlement Only Transmission Energy Storage System (SOTESS)” upon system implementation:]  **Settlement Only Energy Storage System (SOESS)**  An Energy Storage System (ESS) that is settled for imported/exported energy only, but may not participate in the Ancillary Services market, Reliability Unit Commitment (RUC), Security-Constrained Economic Dispatch (SCED), or submit energy offers or bids, and that is registered as a Settlement Only Energy Storage System (SOESS). These units include:  ***Settlement Only Distribution Energy Storage System (SODESS)***  A Settlement Only Energy Storage System (SOESS) connected to the Distribution System with a nameplate capacity of at least one MW and no more than ten MW.  ***Settlement Only Transmission Energy Storage System (SOTESS)***  A Settlement Only Energy Storage System (SOESS) connected to the ERCOT Transmission Grid with a nameplate capacity of at least one MW and no more than ten MW that is not registered as an Energy Storage Resource (ESR). |

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| [NPRR995: Insert the following definitions “Settlement Only Generator (SOG)”, “Settlement Only Distribution Generator (SODG)”, “Settlement Only Transmission Generator (SOTG)”, and “Settlement Only Transmission Self-Generator (SOTSG)” upon system implementation:]  **Settlement Only Generator (SOG)**  A generator that is settled for exported energy only, but which may not participate in the Ancillary Services market, Reliability Unit Commitment (RUC), Security-Constrained Economic Dispatch (SCED), or submit energy offers, and that is registered as a Settlement Only Generator (SOG). These units include:  ***Settlement Only Transmission Generator (SOTG)***  An SOG that is connected to the ERCOT Transmission Grid with a nameplate capacity of at least one MW and no more than ten MW.  ***Settlement Only Transmission Self-Generator (SOTSG)***  An SOG that is connected to the ERCOT Transmission Grid with a nameplate capacity of one MW or more and whose owner is registered with the Public Utility Commission of Texas (PUCT) as a self-generator. |

## 2.2 ACRONYMS AND ABBREVIATIONS

**NSDG** Non-Settled Distribution Generator

**NSG** Non-Settled Generator

**NSTG** Non-Settled Transmission Generator

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

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

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

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

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

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

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

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

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

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

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

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

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

3.6.2 Decision Making Entity for a Resource

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

***3.8.1 Split Generation Resources***

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

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

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

(4) The Master QSE shall:

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

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

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

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

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

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

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

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

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

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

***3.8.7 Self-Limiting Facility***

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

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

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

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

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

(4) If requested by ERCOT, the relevant QSE shall provide meter data to confirm whether the established limits for a Self-Limiting Facility were violated. The TDSP or NOIE serving a Non-Settled Generator (NSG) shall provide monthly meter data to ERCOT to confirm that the limits for the NSG were not violated.

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

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

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

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

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

***3.8.9 Interconnection of a Non-Settled Generator***

(1) As a condition for the interconnection of a new Non-Settled Generator (NSG) to the ERCOT System, the owner shall comply with the requirements of Section 5 of the Planning Guide, Generator Interconnection or Modification, and provide all data required to both its interconnecting TDSP and ERCOT.

(2) As a condition for maintaining interconnection of an existing NSG, the owner of each NSG that is interconnected to the ERCOT System shall submit and update all required data.

(3) The owner of an NSG with an installed capacity greater than one MW and no more than ten MW must provide in the format required by ERCOT, the following categories of data to ERCOT using Resource Integration and Ongoing Operation (RIOO):

(a) Nameplate capacity;

(b) Generator and Fuel type;

(c) Physical location address or coordinates;

(d) Operational contact;

(e) Metering information;

(f) Electrical bus assignment;

(g) Generation Interconnection Agreement or Proof of Operational Status; and

(h) Owner contact information, including designation of an Authorized Representative.

(4) In addition to the information required by paragraph (3) above, the owner of an NSTG greater than one MW shall provide the following information:

(a) Project information;

(b) Substation data;

(c) Generator data;

(d) Transformer data;

(e) Breaker and Switch data;

(f) Load data;

(g) Dynamic model data;

(h) Facility One-line;

(i) Other data as specified by ERCOT.

(5) The owner of an NSG with an installed capacity of greater than ten MW must:

(a) In addition to the information required in paragraph (3) above, the following categories of data must be provided in the format required by ERCOT and posted on the ERCOT NSG webpage:

(i) Net real power injection at the Point of Interconnection (POI);

(ii) Net real power withdrawal at the POI;

(iii) Gross real power output at the generator terminals; and

(iv) Gross real power withdrawal at generator terminals.

(b) Designate a QSE, for the purposes of providing telemetry requirements as listed in the Protocols. The owner of the NSG shall designate a QSE by submitting, through RIOO, Section 23, Form U, NSG QSE Acknowledgement, to ERCOT no later than 45 days prior to the Network Operations Model change date for the NSG, as described in Section 3.10.1, Timeline for Network Operations Model Changes.

(i) The owner of the NSG must follow the processes applicable to Resource Entities for changing a QSE designation provided in Section 16.5.3.

(6) The owner of an NSG must update information provided to ERCOT under paragraphs (3) or (4) above when changes regarding the NSG occur and must promptly respond to any request for information from ERCOT regarding the NSG.

(7) As a condition for allowing a customer to interconnect to a TDSP’s system, the TDSP shall verify that an owner of an NSG has complied with its obligations under the Protocols or Planning Guide. If an owner of an NSG fails to comply with its obligations under the Protocols or Planning Guide, upon notice from ERCOT, the interconnecting TDSP shall disconnect the NSG from the ERCOT System.

**3.10.7.2 Modeling of Generators, Energy Storage Systems, and Transmission Loads**

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

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| ***[NPRR995: Replace paragraph (1) above with the following upon system implementation:]***  (1) Each Resource Entity shall provide ERCOT and its interconnecting TSP with information describing each of its Generation Resources, ESRs, SOGs, SOESSs, and Load Resources connected to the ERCOT System. All Transmission Generation Resources (TGRs), Transmission ESRs (TESRs), Settlement Only Transmission Generators (SOTGs), Settlement Only Transmission Self-Generators (SOTSGs), Settlement Only Transmission Energy Storage Systems (SOTESSs), and the non-TSP MPTs greater than ten MVA, must be modeled to provide equivalent generation injections to the ERCOT Transmission Grid. ERCOT shall coordinate the modeling of Generation Resources, ESRs, Private Use Networks, and Load Resources with their owners to ensure consistency between TSP models and ERCOT models. |

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

(3) Each Resource Entity representing a Distribution Generation Resource (DGR) or Distribution Energy Storage Resource (DESR) that is registered with ERCOT pursuant to Section 16.5, Registration of a Resource Entity, shall provide ERCOT, its interconnecting DSP, and the TSP that interconnects the DSP to the transmission system with information describing each of its DGR or DESR facilities, and additional information and telemetry as required by ERCOT and the interconnecting DSP. ERCOT shall coordinate with representatives of the Resource Entity to represent the registered DGR or DESR facilities at their appropriate Electrical Bus in the Network Operations Model.

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

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| ***[NPRR995: Replace paragraph (4) above with the following upon system implementation:]***  (4) Each Resource Entity representing a Settlement Only Distribution Generator (SODG) or Settlement Only Distribution Energy Storage System (SODESS) facility that is registered with ERCOT pursuant to paragraph (5) of Section 16.5 shall provide ERCOT, its interconnecting DSP, and the TSP that interconnects the DSP to the transmission system with information describing each of its SODG or SODESS facilities, and additional information and telemetry as required by ERCOT. ERCOT shall coordinate with representatives of the Resource Entity to map registered SODG or SODESS facilities to their appropriate Load in the Network Operations Model. |

(5) The owner or designated agent of a Non-Settled Generator (NSG) shall provide ERCOT, its interconnecting DSP, if applicable, and the TSP that interconnects the NSG to the transmission system with information describing each of its NSG facilities. ERCOT shall coordinate with the owner or designated agent of the NSG to represent the NSG facilities at their appropriate electrical bus in the Network Operations Model.

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

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

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

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| ***[NPRR857 and NPRR1234: Replace applicable portions of paragraph (8) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities for NPRR857; or upon system implementation for NPRR1234:]***  (8) Each TSP and DCTO shall provide ERCOT with information describing all transmission Load connections on the ERCOT Transmission Grid. Individual Load connections may be combined, at the discretion of ERCOT, with other Load connections on the same transmission line to represent a Load Point to facilitate state estimation of Loads that do not telemeter Load measurements. ERCOT shall define “Load Points”, which may be one or more combined Loads, for use in its Network Operations Model. A Load Point cannot be used to represent Load connections that are in different Load Zones. |

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

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| ***[NPRR857: Replace paragraph (9) 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:]***  (9) ERCOT may require TSPs and DCTOs to provide additional Load telemetry to provide adequate modeling of the transmission system in accordance with Section 3.10.7.5, Telemetry Standards. When the TSP or DCTO does not own the station for which additional Load telemetry is being requested, the TSP shall request that the owner make the telemetry available. The TSP or DCTO shall notify ERCOT if the owner does not comply with the request. |

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

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

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

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

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

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

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

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

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

(e) Either:

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

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

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

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

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

(15) For each Load Point within the ERCOT Network Operations Model, each TSP shall identify and provide an end-use industry classification when a Load Point represents a single end-use Customer or Service Delivery Point that has a historical or requested peak Demand of 25 MW or greater, either:

(a) By itself;

(b) In combination with other Load Points in the same substation that serve the same Customer or Service Delivery Point;

(c) Where, in addition to a Customer or Service Delivery Point with a 25 MW or larger peak Demand, other Customers with historical or requested Demands smaller than 25 MW that are not required to be modeled also take service at the same Load Point; or

(d) Where the single Customer or Service Delivery Point is served by multiple substations.

(16) The applicable TSP shall identify Load Points subject to the requirements of paragraph (15) above in the Network Operations Model according to the following schedule:

(a) Load Points associated with an interconnecting Customer with a requested peak Demand of 25 MW or greater shall be modeled prior to energization;

(b) Load Points associated with a Customer or Service Delivery Point with a historical peak Demand of 25 MW or greater achieved prior to January 1, 2025 shall be modeled via a spreadsheet NOMCR on or before September 1, 2025;

(i) For Customers or Service Delivery Points served by a DSP via a wholesale point of delivery provided by a TSP, the DSP shall provide a list of Customers, including end-use industry classification, to the interconnecting TSP on or before August 1, 2025; and

(c) If not already modeled pursuant to paragraph (b) above, Load Points associated with a Customer or Service Delivery Point that achieves a peak Demand of 25 MW or greater on or after January 1, 2025 shall be modeled on or before April 1 of the next calendar year after the peak Demand reached 25 MW via a spreadsheet NOMCR;

(i) For Customers or Service Delivery Points served by a DSP via a wholesale point of delivery provided by a TSP, the DSP shall provide a list of Customers, including end-use industry classification, to the interconnecting TSP on or before March 1.

(17) Each Resource Entity or Interconnecting Entity (IE) associated with an existing or proposed Generation Resource or ESR co-located with a Load as described in Section 10.3.2.3 shall represent the co-located Load using one or more Load Points that are separate from auxiliary Loads for the generator. If the aggregate co-located Load has a historical or requested peak Demand of 25 MW or greater, the Resource Entity or IE shall provide the end-use industry classification best representing the facility for each Load Point that is not an auxiliary Load. Calculation of peak Demand shall exclude the auxiliary Loads associated with Generation Resources or ESRs.

(18) A Resource Entity or IE with co-located Load that has a historical or requested peak Demand of 25 MW or greater provide end-use industry classification according to the following schedule:

(a) The classification of a new co-located Load associated with a new generation interconnection request or with an operational Generation Resource or ESR shall be provided in the Resource Registration data and included in the Network Operations Model prior to energization of the co-located Load;

(b) The classification of an operational co-located Load with a historical peak Demand of 25 MW or greater achieved prior to January 1, 2025 shall be provided via an update to the Resource Registration data on or before September 1, 2025;

(c) The classification of an operational co-located Load that achieves a peak Demand of 25 MW or greater on or after January 1, 2025 shall be provided via an update to the Resource Registration data within three months from the date peak Demand reaches 25 MW;

(19) ERCOT shall treat Load Point identification and end-use classification provided pursuant to paragraphs (15) through (18) of this Section as “Proprietary Customer Information,” as defined in paragraph (1)(r) of Section 1.3.1.1, Items Considered Protected Information.

(20) Each Large Load connected at transmission voltage shall be represented by a single Load Point or multiple Load Points at a single substation in the ERCOT Network Operations Model. No other Loads shall be included in these Load Points.

***3.14.1 Reliability Must Run***

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

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

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

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

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

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

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

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

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

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

(f) A Generation Resource is eligible for RMR status based on criteria established by ERCOT indicating its operation is necessary to support ERCOT System reliability according to the Operating Guides. A combined-cycle generation Facility must be treated as a single unit for RMR purposes unless the combustion turbine and the steam turbine can operate separately. If the steam turbine and combustion turbine can operate separately, and the steam turbine is powered by waste heat from more than one combustion turbine, the combustion turbine accepted for RMR Service and a proportionate part of the steam turbine must be treated as a single unit for RMR purposes. If the combustion turbine accepted for RMR Service can operate separately from the steam turbine, and only the combustion turbine is accepted as an RMR Unit, the RMR energy price will be reduced by the value of the combustion turbine’s waste heat calculated at the Fuel Index Price (FIP), except when the steam turbine is Off-Line.

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

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

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

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| ***[NPRR1240: Replace paragraph (i) above with the following upon system implementation:]***  (i) ERCOT shall post on the ERCOT website all information relative to the use of RMR Units including energy deployed monthly. |

(j) The Resource Entity for the RMR Unit may not use the RMR Unit for:

(i) Participating in the bilateral energy market;

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

(iii) Providing of Ancillary Service to any Entity.

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

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

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

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

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

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

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

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

**3.14.1.9 Generation Resource/Energy Storage Resource Status Updates**

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

**3.14.1.10 Eligible Costs**

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

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

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

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

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

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

(v) Costs associated with maintenance:

(A) Due to required equipment maintenance;

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

**3.14.1.19 Charge for Contributed Capital Expenditures**

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

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

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

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

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

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

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

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

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

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

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

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| ***[NPRR885 and NPRR995: Insert applicable portions of Sections 3.14.4 and 3.14.4.1 below upon system implementation:]***  ***3.14.4 Must-Run Alternative Service***  **3.14.4.1 Overview and Description of MRAs**  (1) Subject to approval by the ERCOT Board, ERCOT may procure Must-Run Alternative (MRA) Service as an alternative to contracting with an RMR Unit if ERCOT determines that the MRA Agreement(s) will, in whole or in part, address the reliability need identified in the RMR study in a more cost-effective manner.  (2) ERCOT will issue a request for proposal (RFP) to solicit offers from QSEs to provide MRA Service.  (a) A QSE may submit an offer in response to the RFP or enter into an MRA Agreement only if it meets all registration and qualification criteria in Section 16.2, Registration and Qualification of Qualified Scheduling Entities.  (b) QSEs whose offers for MRA Service are accepted will be paid according to their offers, subject to the terms of the RFP, MRA Agreement and ERCOT Protocols. A clearing price mechanism shall not be used for awarding offers for MRA Service.  (c) A QSE may submit more than one offer for MRA Service in response to a single RFP. A QSE may not submit the same MRA or MRA Sites in more than one of its offers. ERCOT may award multiple offers to a QSE, so long as the MRA or MRA Sites in an awarded offer are not included in any other awarded offer. A QSE may condition ERCOT’s acceptance of an offer for a Demand Response MRA on ERCOT’s acceptance of an offer for a co-located Other Generation MRA offer.  (d) Demand Response MRAs and Other Generation MRAs, including MRA Sites within aggregated MRAs, that are situated in NOIE service territories, are eligible to provide MRA Service. Any QSE other than the NOIE QSE wishing to represent such MRAs must obtain written authorization allowing the representation from the NOIE in which the MRA is located. This authorization must be signed by an individual with authority to bind the NOIE and must be submitted to ERCOT prior to the submission of an offer in response to the MRA.  (3) An MRA may be connected at either transmission or distribution voltage.  (4) An MRA offer is ineligible to the extent it offers capacity that was included as a Resource in ERCOT’s RMR analysis or in the Load forecasts from the Steady State Working Group (SSWG) base cases used as the basis for the RMR analysis, as provided for in paragraph (3)(a) of Section 3.14.1.2, ERCOT Evaluation Process.  (5) Each MRA must provide at least five MW of capacity.  (6) Eligible MRA resources may include:  (a) A proposed Generation Resource or ESR that was not included in the reliability need evaluation pursuant to paragraph (3)(a) of Section 3.14.1.2.  (i) Proposed Generation Resources or ESRs must adhere to all interconnection requirements, including the requirements of Planning Guide Section 5, Generator Interconnection or Modification.  (ii) If the proposed Generation Resource is an Intermittent Renewable Resource (IRR), the QSE shall provide capacity values based on the Resource’s projected peak average capacity contribution during the MRA Contracted Hours.  (b) Proposed capacity additions to existing Generation Resources or ESRs, if the additional capacity was not included in the reliability need evaluation pursuant to paragraph (3)(a) of Section 3.14.1.2.  (i) Prior to providing MRA Service, the Resource Entity will be required to modify its Resource Registration information and complete necessary interconnection requirements with respect to this additional capacity.  (ii) If the capacity is being added to an IRR, the QSE shall provide capacity values based on the Resource’s projected peak average capacity contribution during the hours identified during the MRA Contracted Hours.  (c) A proposed or existing Distribution Generation Resource (DGR). If the generator is an intermittent renewable generator, the QSE, when responding to an RFP for MRA Service, shall provide capacity values based on the MRA’s projected peak average capacity contribution during the hours identified in the MRA Contracted Hours.  (d) Proposed or existing Demand response assets, which may include Load Resources and ERS Loads.  (e) A proposed or existing Energy Storage System (ESS) registered, or proposed to be registered, with ERCOT as a Settlement Only Energy Storage System (SOESS).  (7) An MRA must be able to provide power injection or Demand response to the ERCOT System at ERCOT’s discretion during the MRA Contracted Hours.  (a) QSE offers in response to an RFP for MRA Service must fully describe all of the MRA’s temporal constraints.  (b) For a Demand Response MRA, QSE offers in response to an RFP for MRA Service must include a statement as to whether the offered capacity is a Weather–Sensitive MRA.  (8) The QSE representing an MRA must be capable of receiving both VDI and XML instructions.  (9) ERCOT will periodically validate an MRA’s telemetry using 15-minute interval meter data.  (10) An MRA for which the MRA or every MRA Site, is metered with either an Advanced Meter or an ERCOT-Polled Settlement (EPS) Meter must be available for qualification testing no later than 10 days prior to the first day of the contracted MRA Service.  Other MRAs must be available for qualification testing no later than 45 days prior to the first day of the contracted MRA Service.  (11) All MRA Sites within an MRA must be of the same type (i.e., all Generation Resource MRA, ESR MRA, Other Generation MRA, or Demand Response MRA).  (12) A QSE representing an MRA shall submit to ERCOT and continuously update an Availability Plan for each MRA Contracted Hour for the current Operating Day and the next six Operating Days.  (13) A QSE representing an MRA or MRA Site may not submit DAM Offers, provide an Ancillary Service or carry an ERS responsibility on behalf of any MRA or MRA Site during the MRA Contracted Hours. Demand Response MRAs may not participate in TDSP standard offer programs during any MRA Contracted Hours.  (14) A Combined Cycle Train serving as an MRA must be configured as a single Combined Cycle Generation Resource.  (15) QSEs representing MRAs shall submit offers using an MRA offer sheet as provided by ERCOT.  (16) QSEs must submit the following information for each MRA offer:  (a) The capacity, months and hours offered;  (b) For an aggregated MRA, the offered capacity allocated to each MRA Site for all months and hours offered;  (c) The Resource ID, ESI ID and or unique meter ID associated with the MRA, or in the case of an aggregated MRA, a list of the Resource IDs, ESI IDs and/or unique meter IDs of the offered MRA Sites;  (d) The MRA Standby Price, represented in dollars per MW per hour;  (e) Required capital expenditure, if any, if the MRA offer is awarded;  (f) The MRA Event Deployment Price, in dollars per deployment event, or proxy fuel consumption rate;  (g) The ramp period or startup time of the MRA or aggregated MRA;  (h) The MRA Variable Price, in dollars per MW per hour, and/or proxy heat rate;  (i) The target availability of the MRA or aggregated MRA; and  (j) Any additional information required by ERCOT within the RFP.  (17) Demand Response MRAs shall not be deployed more than once per Operating Day.  (18) Except for a Forced Outage, any Outage of an MRA must be approved by ERCOT.  (19) For any MRA that is registered with ERCOT as a Resource, the QSE representing the MRA must be the same as the QSE representing the Resource. |

**3.15 Voltage Support**

(1) ERCOT, in coordination with the Transmission Service Providers (TSPs), shall establish and update, as necessary, the ERCOT System Voltage Profile and shall post it on the Market Information System (MIS) Secure Area. ERCOT, the interconnecting TSP, or that TSP’s agent, may modify the Voltage Set Point described in the Voltage Profile based on current system conditions.

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| ***[NPRR1240: Replace paragraph (i) above with the following upon system implementation:]***  (1) ERCOT, in coordination with the Transmission Service Providers (TSPs), shall establish and update, as necessary, the ERCOT System Voltage Profile and shall post it on the ERCOT website. ERCOT, the interconnecting TSP, or that TSP’s agent, may modify the Voltage Set Point described in the Voltage Profile based on current system conditions. |

(2) All Generation Resources (including self-serve generating units) and Energy Storage Resources (ESRs) that are connected to Transmission Facilities and that have a gross unit rating greater than 20 MVA or those units connected at the same Point of Interconnection Bus (POIB) that have gross unit ratings aggregating to greater than 20 MVA, or SOG that is part of the Bulk Electric System (BES) as defined by NERC 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 Resource or SOG that is part of the BES as defined by NERC.

(4) Each Resource or SOG required to provide VSS shall comply with the following Reactive Power requirements in Real-Time operations when issued a Voltage Set Point by a TSP or ERCOT:

(a) An over-excited (lagging or producing) power factor capability of 0.95 or less determined at the unit's maximum net power to be supplied to the ERCOT Transmission Grid and for any Voltage Set Point from 0.95 per unit to 1.04 per unit, as measured at the POIB;

(b) An under-excited (leading or absorbing) power factor capability of 0.95 or less, determined at the unit's maximum net power to be supplied to the ERCOT Transmission Grid and for any Voltage Set Point from 1.0 per unit to 1.05 per unit, as measured at the POIB;

(c) For any Voltage Set Point outside of the voltage ranges described in paragraphs (a) and (b) above, the Generation Resource or ESR shall supply or absorb the maximum amount of Reactive Power available within its inherent capability and the capability of any VAr-capable devices as necessary to achieve the Voltage Set Point;

(d) When a Generation Resource or an ESR required to provide VSS is issued a new Voltage Set Point, that Generation Resource or ESR shall make adjustments in response to the new Voltage Set Point, regardless of whether the current voltage is within the tolerances identified in paragraph (4) of Nodal Operating Guide Section 2.7.3.5, Resource Entity Responsibilities and Generation Resource and Energy Storage Resource Requirements;

(e) For Generation Resources, the Reactive Power capability shall be available at all MW output levels and may be met through a combination of the Generation Resource’s Corrected Unit Reactive Limit (CURL), which is the generating unit’s dynamic leading and lagging operating capability, and/or dynamic VAr-capable devices. This Reactive Power profile is depicted graphically as a rectangle. For Intermittent Renewable Resources (IRRs), the Reactive Power requirements shall be available at all MW output levels at or above 10% of the IRR’s nameplate capacity. When an IRR is operating below 10% of its nameplate capacity and is unable to support voltage at the POIB, ERCOT, the interconnecting TSP, or that TSP’s agent may require an IRR to disconnect from the ERCOT System for purposes of maintaining reliability. For ESRs, the Reactive Power capability shall be available at all MW levels, when charging or discharging, and may be met through a combination of the ESR’s CURL, and/or dynamic VAr-capable devices. For any ESR that achieved Initial Synchronization before December 16, 2019, the requirement to have Reactive Power capability when charging does not apply if the Resource Entity for the ESR has submitted a notarized attestation to ERCOT stating that, since the date of Initial Synchronization, the ESR has been unable to comply with this requirement without physical or software changes/modifications, and ERCOT has provided written confirmation of the exemption to the Resource Entity. The exemption shall apply only to the extent of the ESR’s inability to comply with the requirement when the ESR is charging.

(f) For any Generation Resource or ESR that is part of a Self-Limiting Facility, the capabilities described in paragraphs (a) and (b) above shall be determined based on the Self-Limiting Facility’s established MW Injection limit and, if applicable, established MW Withdrawal limit.

(5) As part of the technical Resource testing requirements prior to the Resource Commissioning Date, all Generation Resources and ESRs must conduct an engineering study, and demonstrate through performance testing, the ability to comply with the Reactive Power capability requirements in paragraph (4), (7), (8), or (9) of this Section, as applicable. Any study and testing results must be accepted by ERCOT prior to the Resource Commissioning Date.

(6) Except for a Generation Resource or an ESR subject to Planning Guide Section 5.2.1, Applicability, a Generation Resource or an ESR that has already been commissioned is not required to submit a new reactive study or conduct commissioning-related reactive testing, as described in paragraph (5) above.

(7) Wind-powered Generation Resources (WGRs) that commenced operation on or after February 17, 2004, and have a signed Standard Generation Interconnection Agreement (SGIA) on or before December 1, 2009 (“Existing Non-Exempt WGRs”), must be capable of producing a defined quantity of Reactive Power to maintain a set point in the Voltage Profile established by ERCOT in accordance with the Reactive Power requirements established in paragraph (4) above, except in the circumstances described in paragraph (a) below.

(a) Existing Non-Exempt WGRs whose current design does not allow them to meet the Reactive Power requirements established in paragraph (4) above must conduct an engineering study using the Summer/Fall 2010 on-peak/off-peak Voltage Profiles, or conduct performance testing to determine their actual Reactive Power capability. Any study or testing results must be accepted by ERCOT. The Reactive Power requirements applicable to these Existing Non-Exempt WGRs will be the greater of: the leading and lagging Reactive Power capabilities established by the Existing Non-Exempt WGR’s engineering study or testing results; or Reactive Power proportional to the real power output of the Existing Non-Exempt WGR (this Reactive Power profile is depicted graphically as a triangle) sufficient to provide an over-excited (lagging) power factor capability of 0.95 or less and an under-excited (leading) power factor capability of 0.95 or less, both determined at the WGR’s set point in the Voltage Profile established by ERCOT, and both measured at the POIB.

(i) Existing Non-Exempt WGRs shall submit the engineering study results or testing results to ERCOT no later than five Business Days after its completion.

(ii) Existing Non-Exempt WGRs shall update any and all Resource Registration data regarding their Reactive Power capability documented by the engineering study results or testing results.

(iii) If the Existing Non-Exempt WGR’s engineering study results or testing results indicate that the WGR is not able to provide Reactive Power capability that meets the triangle profile described in paragraph (a) above, then the Existing Non-Exempt WGR will take steps necessary to meet that Reactive Power requirement depicted graphically as a triangle by a date mutually agreed upon by the Existing Non-Exempt WGR and ERCOT. The Existing Non-Exempt WGR may meet the Reactive Power requirement through a combination of the WGR’s Unit Reactive Limit (URL) and/or automatically switchable static VAr-capable devices and/or dynamic VAr-capable devices. No later than five Business Days after completion of the steps to meet that Reactive Power requirement, the Existing Non-Exempt WGR will update any and all Resource Registration data regarding its Reactive Power and provide written notice to ERCOT that it has completed the steps necessary to meet its Reactive Power requirement.

(iv) For purposes of measuring future compliance with Reactive Power requirements for Existing Non-Exempt WGRs, results from performance testing or the Summer/Fall 2010 on-peak/off-peak Voltage Profiles utilized in the Existing Non-Exempt WGR’s engineering study shall be the basis for measuring compliance, even if the Voltage Profiles provided to the Existing Non-Exempt WGR are revised for other purposes.

(b) Existing Non-Exempt WGRs whose current design allows them to meet the Reactive Power requirements established in paragraph (4) above (depicted graphically as a rectangle) shall continue to comply with that requirement. ERCOT, with cause, may request that these Existing Non-Exempt WGRs provide further evidence, including an engineering study, or performance testing, to confirm accuracy of Resource Registration data supporting their Reactive Power capability.

(8) Qualified Renewable Generation Resources (as described in Section 14, State of Texas Renewable Energy Credit Trading Program) in operation before February 17, 2004, required to provide VSS and all other Generation Resources required to provide VSS that were in operation prior to September 1, 1999, whose current design does not allow them to meet the Reactive Power requirements established in paragraph (4) above, will be required to maintain a Reactive Power requirement as defined by the Generation Resource’s URL that was submitted to ERCOT and established per the criteria in the ERCOT Operating Guides.

(9) New generating units connected before May 17, 2005, whose owners demonstrate to ERCOT’s satisfaction that design and/or equipment procurement decisions were made prior to February 17, 2004, based upon previous standards, whose design does not allow them to meet the Reactive Power requirements established in paragraph (4) above, will be required to maintain a Reactive Power requirement as defined by the Generation Resource’s URL that was submitted to ERCOT and established per the criteria in the Operating Guides.

(10) For purposes of meeting the Reactive Power requirements in paragraphs (4) through (9) above, multiple units including IRRs shall, at a Resource Entity’s option, be treated as a single Resource if the units are connected to the same transmission bus.

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

(12) A Resource Entity and TSP may enter into an agreement in which the Generation Resource or ESR compensates the TSP to provide VSS to meet the Reactive Power requirements of paragraph (4) above in part or in whole. The TSP shall certify to ERCOT that the agreement complies with the Reactive Power requirements of paragraph (4).

(13) Unless specifically approved by ERCOT, no unit equipment replacement or modification at a Generation Resource or ESR shall reduce the capability of the unit below the Reactive Power requirements that applied prior to the replacement or modification. The addition of 20 MW or more of Load to a site that includes one or more Generation Resources or ESRs constitutes a modification to the Generation Resource or ESR that requires a new Reactive Power study.

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

(15) All WGRs must provide a Real-Time SCADA point that communicates to ERCOT the number of wind turbines that are available for real power and Reactive Power injection into the ERCOT Transmission Grid. WGRs must also provide two other Real-Time SCADA points that communicate to ERCOT the following:

(a) The number of wind turbines that are not able to communicate and whose status is unknown; and

(b) The number of wind turbines out of service and not available for operation.

(16) All PhotoVoltaic Generation Resources (PVGRs) must provide a Real-Time SCADA point that communicates to ERCOT the capacity of PhotoVoltaic (PV) equipment that is available for real power and Reactive Power injection into the ERCOT Transmission Grid. PVGRs must also provide two other Real-Time SCADA points that communicate to ERCOT the following:

(a) The capacity of PV equipment that is not able to communicate and whose status is unknown; and

(b) The capacity of PV equipment that is out of service and not available for operation.

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| ***[NPRR1029: Insert paragraph (17) below upon system implementation and renumber accordingly:]***  (17) Each DC-Coupled Resource must provide a Real-Time SCADA point that communicates to ERCOT the capacity of the intermittent renewable generation component of the Resource that is available for real power and/or Reactive Power injection into the ERCOT System. Each DC-Coupled Resource must also provide Real-Time SCADA points that communicate to ERCOT the following:  (a) The capacity of any PV generation equipment that is not able to communicate and whose status is unknown;  (b) The capacity of any PV generation equipment that is out of service and not available for operation;  (c) The number of any wind turbines that are not able to communicate and whose status is unknown; and  (d) The number of any wind turbines out of service and not available for operation. |

(17) For the purpose of complying with the Reactive Power requirements under this Section 3.15, Reactive Power losses that occur on privately-owned transmission lines behind the POIB may be compensated by automatically switchable static VAr-capable devices.

**6.5.5.2 Operational Data Requirements**

(1) ERCOT shall use Operating Period data to monitor and control the reliability of the ERCOT Transmission Grid and shall use it in network analysis software to predict the short-term reliability of the ERCOT Transmission Grid. Each TSP, at its own expense, may obtain that Operating Period data from ERCOT or directly from QSEs.

(2) A QSE representing a Generation Resource connected to Transmission Facilities or distribution facilities shall provide the following Real-Time telemetry data to ERCOT for each Generation Resource. ERCOT shall make that data available, in accordance with ERCOT Protocols, NERC Reliability Standards, and Governmental Authority requirements, to requesting TSPs and DSPs operating within ERCOT. Such data must be provided to the requesting TSP or DSP at the requesting TSP’s or DSP’s expense, including:

(a) Net real power (in MW) as measured by installed power metering or as calculated in accordance with the Operating Guides based on metered gross real power and conversion constants determined by the Resource Entity and provided to ERCOT through the Resource Registration process. Net real power represents the actual generation of a Resource for all real power dispatch purposes, including use in Security-Constrained Economic Dispatch (SCED), High Dispatch Limit (HDL), and Low Dispatch Limit (LDL), and is consistent with telemetered HSL, LSL, and Frequency Responsive Capacity (FRC);

(b) Gross real power (in MW) as measured by installed power metering or as calculated in accordance with the Operating Guides based on metered real power, which may include Supervisory Control and Data Acquisition (SCADA) metering, and conversions constants determined by the Resource Entity and provided to ERCOT through the Resource Registration process;

(c) Gross Reactive Power (in Megavolt-Amperes reactive (MVAr));

(d) Net Reactive Power (in MVAr);

(e) Power to standby transformers serving plant auxiliary Load;

(f) Status of switching devices in the plant switchyard not monitored by the TSP or DSP affecting flows on the ERCOT Transmission Grid;

(g) Any data mutually agreed to by ERCOT and the QSE to adequately manage system reliability;

(h) Generation Resource breaker and switch status;

(i) HSL (Combined Cycle Generation Resources) shall:

(i) Submit the HSL of the current operating configuration; and

(ii) When providing ECRS, update the HSL as needed, to be consistent with Resource performance limitations of ECRS provision;

(j) NFRC currently available (unloaded) and included in the HSL of the Generation Resource;

(k) High Emergency Limit (HEL), under Section 6.5.9.2, Failure of the SCED Process;

(l) Low Emergency Limit (LEL), under Section 6.5.9.2;

(m) LSL;

(n) Configuration identification for Combined Cycle Generation Resources;

(o) For Resources with capacity that is not capable of providing Primary Frequency Response, the high and low limits in MW of the Resource’s capacity that is frequency responsive and the current FRC of the Resource;

(p) For RRS, including any sub-categories of RRS, the physical capability (in MW) of the Resource to provide RRS;

(q) For Ancillary Services other than RRS, a blended Normal Ramp Rate (in MW/min) that reflects the physical capability of the Resource to provide that specific type of Ancillary Service;

(r) Five-minute blended Normal Ramp Rates (up and down);

(s) The designated Master QSE of a Generation Resource that has been split to function as two or more Split Generation Resources shall provide Real-Time telemetry for items (a), (b), (c), (d), (e), (g), and (h) above, PSS and AVR status for the total Generation Resource in addition to the Split Generation Resource the Master QSE represents; and

(t) The telemetered MW of power augmentation capacity that is not On-Line for Resources that have power augmentation capacity included in HSL. When power augmentation capacity is On-Line, this value should be zero.

(3) For each Intermittent Renewable Resource (IRR), the QSE shall set the HSL equal to the current net output capability of the facility. The net output capability should consider the net real power of the IRR generation equipment, IRR generation equipment availability, weather conditions, and whether the IRR net output is being affected by compliance with a SCED Dispatch Instruction.

(4) For each Resource, the QSE for the Resource shall consider the physical capability to provide a specific type of Ancillary Service based on the operating conditions for that specific Ancillary Service, including equipment availability, weather conditions and ability to meet the Ancillary Service criteria specified in Section 8.1.1.3, Ancillary Service Capacity Compliance Criteria. ERCOT may perform validation of the QSE’s submission to ensure these criteria are considered and adhered to.

(5) For each Aggregate Generation Resource (AGR), the QSE shall telemeter the number of its generators online.

(6) A QSE representing a Load Resource connected to Transmission Facilities or distribution facilities shall provide the following Real-Time data to ERCOT for each Load Resource and ERCOT shall make the data available, in accordance with ERCOT Protocols, NERC standards and policies, and Governmental Authority requirements, to the Load Resource’s host TSP or DSP at the TSP’s or DSP’s expense. The Load Resource’s net real power consumption, Low Power Consumption (LPC) and Maximum Power Consumption (MPC) shall be telemetered to ERCOT using a positive (+) sign convention:

(a) Load Resource net real power consumption (in MW);

(b) Any data mutually agreed to by ERCOT and the QSE to adequately manage system reliability;

(c) Load Resource breaker status, if applicable;

(d) LPC (in MW);

(e) MPC (in MW);

(f) The Load Resource’s Ancillary Service self-provision (in MW) for RRS and/or ECRS provided via under-frequency relay;

(g) The status of the high-set under-frequency relay, if required for qualification. The under-frequency relay for a Load Resource providing Non-Spin shall be disabled and the status of that relay shall indicate it as disabled or unarmed;

(h) For a Controllable Load Resource (CLR) providing Non-Spin, the Scheduled Power Consumption that represents zero Ancillary Service deployments;

(i) For a single-site CLR with registered maximum Demand response capacity of ten MW or greater, net Reactive Power (in MVAr);

(j) Resource Status;

(k) For an Aggregate Load Resource (ALR) providing Non-Spin, the “Scheduled Power Consumption Plus Two Hours,” representing the QSE’s forecast of the CLR’s instantaneous power consumption for a point two hours in the future;

(l) For RRS, including any sub-categories of RRS, the current physical capability (in MW) of the Resource to provide RRS;

(m) For Ancillary Service products other than RRS, a blended Normal Ramp Rate (in MW/min) that reflects the current physical capability of the Resource’s ability to provide a particular Ancillary Service product; and

(n) For a CLR, 5-minute blended Normal Ramp Rates (up and down).

(7) A QSE representing an ESR connected to Transmission Facilities or distribution facilities shall provide the following Real-Time telemetry data to ERCOT for each ESR. ERCOT shall make that data available, in accordance with ERCOT Protocols, NERC Reliability Standards, and Governmental Authority requirements, to requesting TSPs and DSPs operating within ERCOT. Such data must be provided to the requesting TSP or DSP at the requesting TSP’s or DSP’s expense, including:

(a) Net real power consumption or output (in MW) as measured by installed power metering or as calculated in accordance with the Operating Guides based on metered gross real power and conversion constants determined by the Resource Entity and provided to ERCOT through the Resource Registration process. Net real power represents the actual generation or consumption of an ESR for all real power dispatch purposes, including use in SCED, in determination of HDL, and LDL and is consistent with telemetered HSL, LSL and FRC;

(b) Gross real power consumption or output (in MW) as measured by installed power metering or as calculated in accordance with the Operating Guides based on metered real power, which may include Supervisory Control and Data Acquisition (SCADA) metering, and conversion constants determined by the Resource Entity and provided to ERCOT through the Resource Registration process;

(c) Gross Reactive Power (in Megavolt-Amperes reactive (MVAr));

(d) Net Reactive Power (in MVAr);

(e) Power to standby transformers serving plant auxiliary Load;

(f) Status of switching devices in the plant switchyard not monitored by the TSP or DSP affecting flows on the ERCOT Transmission Grid;

(g) Any data mutually agreed to by ERCOT and the QSE to adequately manage system reliability;

(h) ESR breaker and switch status;

(i) HSL;

(j) HEL, under Section 6.5.9.2, Failure of the SCED Process;

(k) LEL, under Section 6.5.9.2;

(l) LSL;

(m) For RRS, including any sub-category of RRS, the current physical capability (in MW) of the Resource to provide RRS;

(n) For Ancillary Services other than RRS, a blended ramp rate (in MW/min) that reflects the current physical capability of the Resource to provide that specific type of Ancillary Service; and

(o) Five-minute blended normal up and down ramp rates;

(8) A QSE with Resources used in SCED shall provide communications equipment to receive ERCOT-telemetered control deployments.

(9) A QSE providing any Regulation Service shall provide telemetry indicating the appropriate status of Resources providing Reg-Up or Reg-Down, including status indicating whether the Resource is temporarily blocked from receiving Reg-Up and/or Reg-Down deployments from the QSE. This temporary blocking will be indicated by the enabling of the Raise Block Status and/or Lower Block Status telemetry points.

(a) Raise Block Status and Lower Block Status are telemetry points used in transient unit conditions to communicate to ERCOT that a Resource’s ability to adjust its output has been unexpectedly impaired.

(b) When one or both of the telemetry points are enabled for a Resource, ERCOT will cease using the regulation capacity assigned to that Resource for Ancillary Service deployment.

(c) This hiatus of deployment will not excuse the Resource’s obligation to provide the Ancillary Services for which it has been awarded.

(d) These telemetry points shall only be utilized during unforeseen transient unit conditions such as plant equipment failures. Raise Block Status and Lower Block Status shall only be enabled until the Resource operator has time to update the Resource limits and Ancillary Service telemetry to reflect the problem.

(e) The Resource limits and Ancillary Service telemetry shall be updated as soon as practicable.  Raise Block Status and Lower Block Status will then be disabled.

(10) Real-Time data for reliability purposes must be accurate to within three percent. This telemetry may be provided from relaying accuracy instrumentation transformers.

(11) Each QSE shall report the current configuration of combined-cycle Resources that it represents to ERCOT. The telemetered Resource Status for a Combined Cycle Generation Resource may only be assigned a Resource Status of OFF if no generation units within that Combined Cycle Generation Resource are On-Line.

(12) A QSE representing Combined Cycle Generation Resources shall provide ERCOT with the possible operating configurations for each power block with accompanying limits. Combined Cycle Train power augmentation methods may be included as part of one or more of the registered Combined Cycle Generation Resource configurations. Power augmentation methods may include:

(a) Combustion turbine inlet air cooling methods;

(b) Duct firing;

(c) Other ways of temporarily increasing the output of Combined Cycle Generation Resources; and

(d) For Qualifying Facilities (QFs), an LSL that represents the minimum energy available for Dispatch by SCED, in MW, from the Combined Cycle Generation Resource based on the minimum stable steam delivery to the thermal host plus a justifiable reliability margin that accounts for changes in ambient conditions.

(13) A QSE representing a Generation Resource other than a Combined Cycle Generation Resource may provide FRC telemetry for the Generation Resource only if the QSE or Resource Entity associated with that Generation Resource has first requested and obtained ERCOT’s approval.

(14) A QSE representing an ESR shall provide the following Real-Time telemetry data to ERCOT for each ESR:

(a) Maximum State of Charge (MaxSOC), in MWh;

(b) Minimum State of Charge (MinSOC), in MWh;

(c) State of Charge (SOC), in MWh;

(d) Maximum Operating Discharge Power Limit, in MW; and

(e) Maximum Operating Charge Power Limit, in MW.

(15) The QSE shall ensure that the SOC is greater than or equal to the MinSOC and less than or equal to the MaxSOC.

(16) In accordance with ERCOT Protocols, NERC Reliability Standards, and Governmental Authority requirements, ERCOT shall make the data specified in paragraph (14) available to any requesting TSP or DSP at the requesting TSP’s or DSP’s expense.

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| ***[NPRR1077: Insert paragraphs (17)-(19) below upon system implementation:]***  (17) Except as provided in paragraph (18) below, a QSE representing a Settlement Only Generator (SOG) shall provide ERCOT the following Real-Time telemetry:  (a) Net real power injection at the Point of Interconnection (POI) or Point of Common Coupling (POCC) for each site with one or more SOGs;  (b) For any site with one or more ESSs that are registered as an SOG, net real power withdrawal at the POI or POCC;  (c) For each inverter at the site, gross real power output measured at the generator terminals for all SOTGs and SOTSGs that are located behind that inverter, separately aggregated by fuel type;  (d) For SOTGs and SOTSGs at the same site that are not located behind an inverter, gross real power output measured at the generator terminals for all SOGs, separately aggregated by fuel type;  (e) For any site with one or more ESSs registered as an SOTG or SOTESS, for each inverter, gross real power withdrawal by all such ESSs that are located behind that inverter, as measured at the generator terminals; and  (f) Generator breaker status.  (18) A QSE is not required to provide telemetry for a Settlement Only Distribution Generator (SODG) if:  (a) The site that includes the SODG has not exported more than 10 MWh in any calendar year, exclusive of any energy exported during any Settlement Interval in which an ERCOT-declared Energy Emergency Alert (EEA) is in effect;  (b) The QSE or Resource Entity for the SODG has submitted a written request to ERCOT seeking an exemption from the telemetry requirements under this paragraph; and  (c) ERCOT has provided the QSE or Resource Entity written confirmation that the SODG is exempt from providing telemetry under this paragraph.  (19) If ERCOT determines that a site that includes an SODG has exported more than 10 MWh in a given calendar year, it shall notify the SODG’s QSE that the SODG is no longer eligible for the telemetry exemption. Within 90 days of receiving this notification, the QSE for the SODG shall comply with the telemetry requirements of paragraph (17) above. |

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| ***[NPRR885: Insert paragraph (20) below upon system implementation:]***  (20) A QSE representing a Must-Run Alternative (MRA) shall telemeter the MRA MW currently available (unloaded) and not included in the HSL. |

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| ***[NPRR1029: Insert paragraph (21) below upon system implementation:]***  (21) A QSE representing a DC-Coupled Resource shall provide the following Real-Time telemetry data in addition to that required for other ESRs:  (a) Gross AC MW production of the intermittent renewable generation component of the DC-Coupled Resource, which includes the portion of the intermittent renewable generation used to charge the ESS and/or serve auxiliary Load on the DC side of the inverter; and  (b) Gross AC MW capability of the intermittent renewable generation component of the DC-Coupled Resource, based on Real-Time conditions. |

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| ***[NPRR995: Insert paragraph (22) below upon system implementation:]***  (22) A QSE representing a Settlement Only Energy Storage System (SOESS) that elects to include the net generation and/or net withdrawals of the SOESS in the estimate of Real-Time Liability (RTL) shall provide ERCOT Real-Time telemetry of the net generation and/or net withdrawals of the SOESS. |

(23) A QSE representing an owner of a Non-Settled Generator (NSG) greater than ten MW shall provide ERCOT with the following Real-Time telemetry:

(a) Net real power injection at the Point of Interconnection (POI);

(b) Net real power withdrawal at the POI;

(c) Gross real power output at the generator terminals;

(d) Gross real power withdrawal at generator terminals; and

(e) Generator breaker status.

***10.2.2 TSP and DSP Metered Entities***

(1) Each Transmission Service Provider (TSP) and Distribution Service Provider (DSP) is responsible for supplying ERCOT with meter data associated with:

(a) All Loads using the ERCOT System;

(b) Any Settlement Only Distribution Generator (SODG); a DSP may make some or all such meters ERCOT-Polled Settlement (EPS) compliant and may request that ERCOT poll the meters. Notwithstanding the foregoing sentence, meter data is not required from:

(i) Generation owned by a Non-Opt-In Entity (NOIE) and used for the NOIE’s self-use (not serving Customer Load);

(ii) Distributed Renewable Generation (DRG) with a design capacity less than 50 kW interconnected to a DSP where the owner chooses not to have the out-flow measured in accordance with P.U.C. Subst. R. 25.213, Metering for Distributed Renewable Generation; and

(iii) Distributed Generation (DG) interconnected to a DSP behind a registered NOIE boundary metering point, not registered as a Generation Resource and with an installed capacity below the DG registration threshold, as determined in Section 16.5, Registration of a Resource Entity, and posted on the ERCOT website; and

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| ***[NPRR1265: Replace paragraph (iii) above with the following upon system implementation:]***  (iii) Unregistered Distributed Generator (UDG) interconnected to a DSP behind a registered NOIE boundary metering point; and |

(c) Any Non-Settled Generator (NSG);

(d) NOIE or External Load Serving Entity (ELSE) points of delivery where metering points are radial Loads and are uni-directionally metered and NOIE points of delivery that have bi-directional flows that are solely the result of generation interconnected to a Transmission and/or Distribution Service Provider (TDSP) owned Distribution System behind a NOIE point of delivery metering point. A TSP or DSP has the option of making some or all such meters EPS compliant and to request that ERCOT poll the meters; and

(e) Generation participating in a current Emergency Response Service (ERS) Contract Period, where such generation only exports energy to the ERCOT System during an ERS deployment or ERS test.

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| ***[NPRR1188: Insert paragraph (f) below upon system implementation:]***  (f) Load that has TDSP read meter(s) and is participating as a Controllable Load Resource (CLR) that is not an Aggregate Load Resource (ALR). The CLR must be metered separately from all other Loads and generation. |

(2) Each TSP and DSP is responsible for the following:

(a) Compliance with the procedures and standards in this Section, the Settlement Metering Operating Guide (SMOG) and the Operating Guides;

(b) Installation, control, and maintenance of the Settlement Metering Facilities, as more fully described in this Section and the SMOG, which includes meters, recorders, instrument transformers, wiring, and miscellaneous equipment required to measure electrical energy;

(c) Costs incurred in the installation and maintenance of these Metering Facilities and communications except for incremental costs incurred for functions not required for the Settlement of the Load or Generation Resource, Energy Storage Resource (ESR), Settlement Only Generator (SOG), or Load Resource. These incremental costs shall be borne by the Entities requesting the service pursuant to the TSP or DSP tariffs; and

(d) Installation, maintenance, data collection, and related communications, telemetry for the Metering Facilities, and related services necessary to meet the mandatory Interval Data Recorder (IDR) requirements detailed in this Section, Section 18, Load Profiling, and the SMOG.

***10.2.3 ERCOT-Polled Settlement Meters***

(1) ERCOT shall poll Metering Facilities that meet any one of the following criteria:

(a) Generation not registered as an NSG, connected directly to the ERCOT Transmission Grid, unless the generation is participating in a current ERS Contract Period and the generation only exports energy to the ERCOT Transmission Grid during equipment testing, an ERS deployment, or an ERS test;

(b) Auxiliary meters used for generation netting by ERCOT;

(c) Generation delivering 10 MW or more to the ERCOT System, unless the generation is participating in a current ERS Contract Period and the generation only exports energy to the ERCOT System during equipment testing, an ERS deployment, or an ERS test;

(d) Generation participating in any Ancillary Service market;

(e) NOIE points connected bi-directionally to the ERCOT System, unless the bi-directional energy flows are the sole result of generation interconnected to a TDSP owned Distribution System behind a NOIE point of delivery metering point;

(f) Direct Current Ties (DC Ties);

(g) DG where there is an energy storage Load Resource that has associated Wholesale Storage Load (WSL);

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| ***[NPRR995: Replace paragraph (g) above with the following upon system implementation:]***  (g) Metering required to determine the Wholesale Storage Load (WSL) or Non-WSL Settlement Only Charging Load associated to a Settlement Only Distribution Energy Storage System (SODESS) or Settlement Only Transmission Energy Storage System (SOTESS); |

(h) Metering required to determine WSL associated with an Energy Storage Resource (ESR); and

(i) Metering required to determine the Non-WSL ESR Charging Load.

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| ***[NPRR1188: Insert paragraph (j) below upon system implementation:]***  (j) Metering required to measure the consumption of a Load that has registered as a CLR with ERCOT and is not an ALR, where the CLR is behind the Point of Interconnection (POI) of a generator, as reflected in an ERCOT-approved EPS Design Proposal. The CLR must be metered separately from all other Loads and generation through a single EPS metering point. |

(2) Additionally, ERCOT shall poll any NSG, SODG or NOIE metering point at the request of such Entity, provided the Metering Facility meets all requirements and approvals associated with EPS metering requirements of this Section and the SMOG. Load Resources of ten MW or more on the ERCOT System, may, at their option have an EPS Meter.

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| ***[NPRR1188: Replace paragraph (2) above with the following upon system implementation:]***  (2) Additionally, ERCOT shall poll any NSG, SODG or NOIE metering point at the request of such Entity, provided the Metering Facility meets all requirements and approvals associated with EPS metering requirements of this Section and the SMOG. Load Resources that have registered as a CLR with ERCOT and are not an ALR, where the CLR is ten MW or more and the CLR is the only Load behind the Service Delivery Point such that it can be separately metered at its Service Delivery Point, may, at their option have an EPS Meter. |

**10.3.2.1 Generation Resource Meter Splitting**

(1) Each Generation Resource must be represented by only one QSE, except that a jointly owned Generation Resource unit or group of Generation Resources may split the net generation output into two or more Split Generation Resources for a Resource Entity. Each Resource Entity representing a Split Generation Resource may have its energy and capacity scheduled through a separate QSE. For purposes of this paragraph, a jointly owned Generation Resource unit or group of Generation Resources shall also include the San Miguel and Gibbons Creek power projects and Intermittent Renewable Resources (IRRs) such as wind and solar generation.

(2) When a Generation Resource that has been split to function as two or more Split Generation Resources is registered with ERCOT, the Resource Entities representing the Split Generation Resources shall be required to submit a percentage allocation of the Generation Resource to be used to determine the capacity available at each Split Generation Resource.

(3) When a Generation Resource that has been split to function as two or more Split Generation Resources is registered with ERCOT, the Entities that own the Generation Resource shall submit all required ERCOT Facility registration documentation and an ERCOT-approved splitting agreement executed by an Authorized Representative from each Resource Entity that represents the Generation Resource. Such agreement shall contain a defined and fixed ownership percentage as among the owning Resource Entities. ERCOT shall establish this Generation Resource as a “split,” essentially establishing Split Generation Resource meters. Generation splitting based on a static ratio is not permitted. Generation splitting requires Real-Time splitting signals.

16.5 Registration of a Generator or Resource Entity

(1) The owner of a generator, including an Energy Storage System (ESS), with a nameplate capacity of one MW or greater and that, as installed, is capable of operating in parallel with the ERCOT System shall register the generator with ERCOT as a Generation Resource, Settlement Only Generator (SOG), Energy Storage Resource (ESR), or Settlement Only Energy Storage System (SOESS), or Non-Settled Generator (NSG).

(2) The owner of a Generation Resource, Energy Storage Resource (ESR), Settlement Only Generator (SOG), or Load Resource connected to the ERCOT System shall ensure that the Generation Resource, ESR, SOG, or Load Resource is represented by a Resource Entity. The Resource Entity designated to represent a Generation Resource, SOG, or Load Resource must either own or be authorized to control the Generation Resource, SOG, or Load Resource.

(3) To become registered as a Resource Entity, an Entity must execute a Standard Form Market Participant Agreement (using the form in Section 22, Attachment A, Standard Form Market Participant Agreement), designate Resource Entity Authorized Representatives, contacts, and a User Security Administrator (USA) (per the Application for Registration as a Resource Entity), and demonstrate to ERCOT’s reasonable satisfaction that it is capable of performing the functions of a Resource Entity under these Protocols. The Resource Entity shall provide Resource Registration data pursuant to Planning Guide Section 6.8.2, Resource Registration Process, for each Resource or SOG through ERCOT registration, except for Distributed Generation (DG) with an installed capacity equal to or lower than the DG registration threshold that has chosen not to register with ERCOT. A Resource Entity may submit a proposal to register the aggregation of generators, with the exception of Intermittent Renewable Resources (IRRs) pursuant to paragraph (13) of Section 3.10.7.2, Modeling of Resources and Transmission Loads, as an Aggregate Generation Resource (AGR) which ERCOT may grant at its sole discretion. A Resource Entity may submit a proposal to register a SOG consisting of an Energy Storage System (ESS) or a combination of ESS and non-ESS generation. The Resource Entity must identify all components of the SOG as part of the Resource Registration process.

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| ***[NPRR995 and NPRR1265: Replace applicable portions of paragraphs (2) and (3) above with the following upon system implementation:]***  (2) An owner of a Generation Resource, Energy Storage Resource (ESR), Settlement Only Generator (SOG), Settlement Only Energy Storage System (SOESS), or Load Resource connected to the ERCOT System shall ensure that the Generation Resource, ESR, SOG, SOESS, or Load Resource is represented by a Resource Entity.  (3) To become registered as a Resource Entity, an Entity must execute a Standard Form Market Participant Agreement (using the form in Section 22, Attachment A, Standard Form Market Participant Agreement), designate Resource Entity Authorized Representatives, contacts, and a User Security Administrator (USA) (per the Application for Registration as a Resource Entity), and demonstrate to ERCOT’s reasonable satisfaction that it is capable of performing the functions of a Resource Entity under these Protocols. The Resource Entity shall provide Resource Registration data pursuant to Planning Guide Section 6.8.2, Resource Registration Process, for each Resource, SOG, or SOESS through ERCOT registration, except for an Unregistered Distribution Generator (UDG). A Resource Entity may submit a proposal to register the aggregation of generators, with the exception of Intermittent Renewable Resources (IRRs) pursuant to paragraph (13) of Section 3.10.7.2, Modeling of Resources and Transmission Loads, as an Aggregate Generation Resource (AGR) which ERCOT may grant at its sole discretion. If a Resource Entity intends to register one or more Energy Storage Systems (ESSs) and one or more non-ESS generators as SOGs at the same site, the Resource Entity must provide an affidavit attesting to the amount of ESS and non-ESS capacity at the site as a condition for registration. |

(4) Prior to commissioning, Resource Entities will regularly update the data necessary for modeling. These updates will reflect the best available information at the time submitted.

(5) Once ERCOT has received a new or amended Standard Generation Interconnection Agreement (SGIA) or a letter from a duly authorized official from the Municipally Owned Utility (MOU) or Electric Cooperative (EC) and has determined that the proposed Generation Resource, ESR, or SOG meets the requirements of Planning Guide Section 6.9, Addition of Proposed Generation to the Planning Models, ERCOT shall review the description of the proposed Generation Resource, ESR, or SOG in Exhibit “C” (or similar exhibit) to the SGIA and the data submitted pursuant to Planning Guide Section 6.8.2 to assess whether the Generation Resource, ESR, or SOG, as proposed, would violate any operational standards established in the Protocols, Planning Guide, Nodal Operating Guides, and Other Binding Documents. ERCOT must provide its determination to the Transmission Service Provider (TSP) and the owner of the proposed Generation Resource, ESR, or SOG within 90 days of the date the Generation Resource, ESR, or SOG meets the conditions for review. Notwithstanding the foregoing, this determination shall not preclude ERCOT from subsequently determining that the Generation Resource, ESR, or SOG violates any operational standards established in the Protocols, Planning Guide, Nodal Operating Guides, and Other Binding Documents or from taking any appropriate action based on that determination.

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| ***[NPRR995: Replace paragraph (5) above with the following upon system implementation:]***  (5) Once ERCOT has received a new or amended Standard Generation Interconnection Agreement (SGIA) or a letter from a duly authorized official from the Municipally Owned Utility (MOU) or Electric Cooperative (EC) and has determined that the proposed Generation Resource, ESR, SOG, or SOESS meets the requirements of Planning Guide Section 6.9, Addition of Proposed Generation to the Planning Models, ERCOT shall review the description of the proposed Generation Resource, ESR, SOG, or SOESS in Exhibit “C” (or similar exhibit) to the SGIA and the data submitted pursuant to Planning Guide Section 6.8.2, to assess whether the Generation Resource, ESR, SOG, or SOESS, as proposed, would violate any operational standards established in the Protocols, Planning Guide, Nodal Operating Guides, and Other Binding Documents. ERCOT must provide its determination to the Transmission Service Provider (TSP) and the owner of the proposed Generation Resource, ESR, SOG, or SOESS within 90 days of the date the Generation Resource, ESR, SOG, or SOESS meets the conditions for review. Notwithstanding the foregoing, this determination shall not preclude ERCOT from subsequently determining that the Generation Resource, ESR, SOG, or SOESS violates any operational standards established in the Protocols, Planning Guide, Nodal Operating Guides, and Other Binding Documents or from taking any appropriate action based on that determination. |

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| ***[NPRR1283: Insert paragraph (6) below on January 1, 2026 and renumber accordingly:]***  (6) An Interconnecting Entity (IE) shall not proceed to Initial Energization of a Generation Resource, ESR, Settlement Only Transmission Generator (SOTG), or Settlement Only Transmission Self-Generator (SOTSG) in the event any required Subsynchronous Oscillation (SSO) studies, SSO Mitigation plan, SSO Protection, and SSO monitoring have not been completed and approved by ERCOT in accordance with Section 3.22, Subsynchronous Oscillation. |

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| ***[NPRR995: Replace paragraph (6) above with the following upon system implementation:]***  (6) An Interconnecting Entity (IE) shall not proceed to Initial Energization of a Generation Resource, ESR, Settlement Only Transmission Generator (SOTG), Settlement Only Transmission Self-Generator (SOTSG), or Settlement Only Transmission Energy Storage System (SOTESS) in the event any required Subsynchronous Oscillation (SSO) studies, SSO Mitigation Plan, SSO Protection, and SSO monitoring have not been completed and approved by ERCOT in accordance with Section 3.22, Subsynchronous Oscillation. |

(6) An Interconnecting Entity (IE) shall not proceed to Initial Synchronization of a Generation Resource, ESR, Settlement Only Transmission Generator (SOTG), or Settlement Only Transmission Self-Generator (SOTSG) in the event of any of the following conditions:

(a) Pursuant to paragraph (5) above, ERCOT has reasonably determined that the Generation Resource, ESR, SOTG, or SOTSG may violate operational standards established in the Protocols, Planning Guide, Nodal Operating Guides, and Other Binding Documents, and the Resource Entity has not yet demonstrated to ERCOT’s satisfaction that the Generation Resource, ESR, SOTG, or SOTSG can comply with these standards;

(b) The requirements of Planning Guide Section 5.3.5, ERCOT Quarterly Stability Assessment, if applicable, have not been completed for the Generation Resource, ESR, SOTG, or SOTSG; or

(c) Any required Subsynchronous Resonance (SSR) studies, SSR mitigation plan, SSR protection, and SSR monitoring if required, have not been completed and approved by ERCOT.

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| ***[NPRR995, NPRR1234, and NPRR1283: Replace applicable portions of paragraph (6) above with the following upon system implementation for NPRR995 or NPRR1234; or on January 1, 2026 for NPRR1283:]***  (6) An Interconnecting Entity (IE) shall not proceed to Initial Synchronization of a Generation Resource, ESR, Settlement Only Transmission Generator (SOTG), Settlement Only Transmission Self-Generator (SOTSG), or Settlement Only Transmission Energy Storage System (SOTESS) in the event of any of the following conditions:  (a) Pursuant to paragraph (3) above, ERCOT has reasonably determined that the Generation Resource, ESR, SOTG, SOTSG, or SOTESS may violate operational standards established in the Protocols, Planning Guide, Nodal Operating Guides, and Other Binding Documents, and the Resource Entity has not yet demonstrated to ERCOT’s satisfaction that the Generation Resource, ESR, SOTG, SOTSG, or SOTESS can comply with these standards; or  (b) The requirements of Planning Guide Section 5.3.5, ERCOT Quarterly Stability Assessment, if applicable, have not been completed for the Generation Resource, ESR, SOTG, SOTSG, or SOTESS. |

**16.5.1.1 Designation of a Qualified Scheduling Entity**

(1) Each Resource Entity applicant within the ERCOT Region shall designate the Qualified Scheduling Entity (QSE) that will perform QSE functions per these Protocols on behalf of the Resource Entity. Each applicant shall acknowledge that it bears sole responsibility for selecting and maintaining a QSE as its representative. The applicant shall include a written statement from the designated QSE acknowledging that the QSE accepts responsibility for the applicant’s transactions pursuant to these Protocols. The Resource Entity for a Resource must submit the Resource Entity’s QSE designation to ERCOT no later than 45 days prior to the Network Operations Model change date, as described in Section 3.10.1, Time Line for Network Operations Model Changes, for the Resource.

(2) If a Resource Entity fails to maintain a QSE as its representative, the Resource Entity may be designated as an Emergency QSE as provided in Section 16.2.6.1, Designation as an Emergency Qualified Scheduling Entity or Virtual Qualified Scheduling Entity.

***16.5.2 Registration Process for a Resource Entity***

(1) To register as a Resource Entity, an applicant must submit to ERCOT a completed Resource Entity application and any applicable fee. ERCOT shall post on the ERCOT website the form in which Resource Entity applications must be submitted, all materials that must be provided with the Resource Entity application.

(2) The Resource Entity application must be attested to by a duly authorized officer or agent of the applicant. The applicant shall promptly notify ERCOT of any material changes affecting a pending Resource Entity application using the appropriate form posted on the ERCOT website.

(3) If the Resource Entity intends to represent a Load Resource located within a Non-Opt-In Entity’s (NOIE’s) service territory, such applicant must designate the NOIE’s QSE, or an alternate QSE authorized by the NOIE. If an alternate QSE is designated, then such QSE representing that Load Resource must first obtain written permission from the NOIE prior to offering any services in the NOIE’s service territory. The alternate QSE shall submit the NOIE’s written permission to ERCOT at the time of designation.

16.5.3 Changing QSE Designation

(1) A Resource Entity may change its designation of QSE with written notice to ERCOT, no more than once in any consecutive three days.

(2) If a Resource Entity’s representation by a QSE will terminate or the Resource Entity intends to be represented by a different QSE, the Resource Entity shall provide the name of the newly designated QSE to ERCOT along with a written statement from the newly designated QSE acknowledging the QSE’s agreement to accept responsibility for the Resource Entity’s transactions under these Protocols. The Resource Entity’s QSE designation must be submitted to ERCOT no later than 45 days before the effective date of the change, unless otherwise approved by ERCOT, before the Resource Entity will be evaluated for compliance with the requirements of paragraph (3) below. ERCOT shall notify the Resource Entity of approval or disapproval as soon as practicable after receipt of the request.

(3) For Resources required by these Protocols to be in the Network Operations Model, the following apply:

(a) The designated QSE shall install all telemetry required of these Protocols for the requesting Resource Entity and schedule point-to-point data verification with ERCOT.

(b) The designated QSE shall submit telemetry data descriptions to ERCOT to meet ERCOT’s normal model update process.

(c) The Resource must submit any changes in system topology or telemetry according to Section 3.3.2.1, Information to Be Provided to ERCOT.

(d) The effective date for the newly designated QSE shall be in accordance with Section 3.10.1, Time Line for Network Operations Model Changes.

(e) ERCOT may request the Resource Entity to develop a transition implementation plan to be approved by ERCOT that sets appropriate deadlines for completion of all required data and telemetry verification and cutover testing activities with ERCOT.

(4) For all other Resources, the new QSE designation is to be received no less than six days prior to the effective date.

(5) Within two days of approving a Resource Entity’s notice, ERCOT shall notify all affected Entities, including the Resource Entity’s current QSE, of the effective date of the change.

18.2 Methodology

(1) A Load Profiling Methodology is the fundamental basis on which Load Profiles are created. The implementation of a Load Profiling Methodology may require statistical Sampling, engineering methods, econometric modeling, or other approaches. All Load Profiles shall conform to the ERCOT-defined Settlement Interval length.

(2) ERCOT has developed Load Profiles for:

(a) Non-interval metered Loads;

(b) Non-Metered Loads; and

(c) Interval Data Recorders (IDRs) including:

(i) Advanced Meters; and

(ii) IDR Meters.

(3) The following Load Profiling Methodologies are used:

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| **Type of Load** | **Load Profiling Methodology** |
| Non-interval metered | Adjusted Static Models |
| Non-interval metered with Distributed Generator (DG) and Non-Settled Distributed Generator (NSDG) | Adjusted Static Models and engineering estimates |
| Non-metered | Engineering estimates |

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| ***[NPRR1265: Replace paragraph (3) above with the following upon system implementation:]***  (3) The following Load Profiling Methodologies are used:   |  |  | | --- | --- | | **Type of Load** | **Load Profiling Methodology** | | Non-interval metered | Adjusted Static Models | | Non-interval metered with Unregistered Distributed Generator (UDG) and Non-Settled Distributed Generator (NSDG) | Adjusted Static Models and engineering estimates | | Non-metered | Engineering estimates | |

**ERCOT Nodal Protocols**

**Section 23**

**Form C: Managed Capacity Declaration**

**TBD**

Date Received: \_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_

**MANAGED CAPACITY DECLARATION**

Pursuant to subsection (d) of P.U.C. Subst. R. 25.502, Pricing Safeguards in Markets Operated by the Electric Reliability Council of Texas, and Section 3.6.2, Decision Making Entity for a Resource, each Resource Entity shall inform ERCOT of the Decision Making Entity (DME) that controls each Resource that it represents, except for Load Resources that are not Security Constrained Economic Dispatch (SCED) qualified, by completing this Declaration.

If the legal entity that represents a Resource is not registered as the Resource Entity, then the Resource Entity that registered the Resource with ERCOT shall complete this Declaration for the Resource and submit it to ERCOT with a signed acknowledgement from the Resource owner authorizing the Resource Entity to complete this Declaration as the owner’s agent and explaining the arrangement or agreement in place.

ERCOT may request additional verification on a case-by-case basis from the relevant Resource Entity in order to verify the DME that controls a Resource. For purposes of this Declaration, “control” is defined as the ultimate decision-making authority over how a Resource is dispatched and priced, either by virtue of ownership or agreement, and a substantial financial stake in the Resource’s profitable operation. All Resources under common control are required to declare the same DME.

For a Split Generation Resource, each Resource Entity that represents a portion of the Split Generation Resource shall separately submit this Declaration to identify the DME that controls the associated portion of the Split Generation Resource.

A Resource Entity shall notify ERCOT of any known changes in its Resource’s DME no later than 14 calendar days prior to the date that the change takes effect, or as soon as possible in a situation where the Resource Entity cannot meet the 14 calendar day notice requirement. However, in no event may the Resource Entity inform ERCOT later than 72 hours before the date on which the change in DME takes effect. In addition, this Managed Capacity Declaration form must be submitted and accepted by ERCOT before these changes are applied to the associated Resource(s).

The signed Declaration form may be submitted electronically through the Market Information System (MIS) as a Service Request, using the Type: MP Registration and Sub-Type: Resource/Asset Registration. Submission through the MIS link requires a valid Authorized Representative’s Digital Certificate. An alternative to MIS is to submit the signed Declaration form in pdf format to both [ercotregistration@ercot.com](mailto:ercotregistration@ercot.com) and [MPRegistration@ercot.com](mailto:MPRegistration@ercot.com).

If questions arise related to the completion of this form, please contact your designated ERCOT Account Manager or email ERCOT Client Services at [ClientServices@ercot.com](mailto:ClientServices@ercot.com) with the subject ”Decision Making Entity Form”.

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| --- | --- | --- | --- | --- |
| **Declaration of Decision Making Entity (DME)** | | | |  |
| **Resource Entity** |  | | | |
| **DUNS Number** |  | | | |
|  | | | | |
| **Resource Site Name** | **Resource Unit Code, as Registered with ERCOT [used when the Resource was registered, such as in RIOO]** | **DME [If DME is currently listed in the** [**Resource Control Report**](http://mis.ercot.com/misapp/GetReports.do?reportTypeId=10036&reportTitle=Daily%20Resource%20Control%20Report&showHTMLView=&mimicKey)**, use name as listed. Do not leave blank.]** | **DME DUNS Number [If new DME, consult** [**Dun & Bradstreet**](https://www.dnb.com/duns/duns-lookup.html)**. Do not leave blank.]** | **Preferred**  **Effective Date** |
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| To view the current registered DME list, open the most recent csv from the  [Resource\_Control\_Report](http://mis.ercot.com/misapp/GetReports.do?reportTypeId=10036&reportTitle=Daily%20Resource%20Control%20Report&showHTMLView=&mimicKey). | | | |  |

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| **General Comments**   |  | | --- | |  |   Authorized Representative indicated and signed below attests that all statements made and information provided in this Declaration are true, correct and complete. | | | | | |
| Signature: |  | | | |  |
| (Authorized Representative signature) | | | | | |
|  |  |  |  |  |  |
| Printed Name: |  | | | |  |
| (Authorized Representative) | | | | | |
|  |  |  |  |  |  |
| Date: |  | |  |  |  |

**ERCOT Nodal Protocols**

**Section 23**

**Form U: NSG QSE Acknowledgement**

**TBD**

**NSG QSE Acknowledgement**

**Acknowledgment by Designated QSE for**

**NSG Telemetry Responsibilities with ERCOT**

The Non-Settled Generator (NSG) below has named the Qualified Scheduling Entity (QSE) listed below as its designated QSE to provide the NSG’s required telemetry to ERCOT.

The NSG’s designated QSE, listed below, hereby acknowledges that represents the NSG and that it shall be responsible for the NSG’s telemetry requirements with ERCOT pursuant to the ERCOT Protocols.

The requested effective date for such representation is:      [[1]](#footnote-1)\*\*

or

Establish partnership at the earliest possible date

Acknowledgment by **QSE**:

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| --- | --- |
| Signature of Authorized Representative (“AR”) for QSE: |  |
| Printed Name of AR: |  |
| Email Address of AR: |  |
| Date: |  |
| Name of Designated QSE: |  |
| DUNS of Designated QSE: |  |

Acknowledgment by **NSG**:

|  |  |
| --- | --- |
| Signature of Authorized Representative (“AR”) for NSG: |  |
| Printed Name of AR: |  |
| Email Address of AR: |  |
| Date: |  |
| Name of NSG: |  |

1. \*\* *Actual effective date will depend on time needed to implement the relationship in ERCOT systems once ERCOT has received all necessary information (a minimum of three Business Days), and may be later than the requested effective date. ERCOT will notify the parties of the actual effective date*. [↑](#footnote-ref-1)