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| **NPRR Number** | [**1296**](https://www.ercot.com/mktrules/issues/NPRR1296) | **NPRR Title** | **Residential Demand Response Program** |
| **Date of Decision** | September 17, 2025 |
| **Action** | Tabled |
| **Timeline**  | Normal |
| **Proposed Effective Date** | To be determined |
| **Priority and Rank Assigned** | To be determined |
| **Nodal Protocol Sections Requiring Revision**  | 2.1, Definitions2.2, Acronyms and Abbreviations3.6.1, Load Resource Participation3.7.1.2, Load Resource Parameters3.14.3.1, Emergency Response Service Procurement3.14.3.4, Emergency Response Service Reporting and Market Communications3.14.4, Must-Run Alternative Service3.26, Residential Demand Response Program (new)3.26.1, Overview (new)3.26.2, Participation (new)3.26.3, Assessment Periods (new)3.26.4, Residential Demand Response Program Cap (new)3.26.5, Residential Demand Response Program Commencement (new)6.9, Residential Demand Response Program Settlement (new)6.9.1, Residential Demand Response Rate (new) 6.9.2, Residential Demand Response Payments (new)6.9.3, Residential Demand Response Charge (new)8.1.4, Residential Demand Response Performance (new)8.1.4.1, REP and NOIE LSE Data Submission Requirements for RDR Program Participation (new)8.1.4.2, Files Sent from ERCOT to RDR Participating REPs and NOIE LSEs (new)8.1.4.3, Performance Criteria for REPs and NOIE LSEs Participating in ERCOT’s Residential Demand Response Program (new)8.1.4.4, Baselines for Residential Demand Response Program (new)9.5.3, Real-Time Market Settlement Charge Types9.5.13, Settlement of Residential Demand Response Program (new)22, Attachment O, Requirements for Aggregate Load Resource Participation in the ERCOT Markets |
| **Related Documents Requiring Revision/Related Revision Requests** | None |
| **Revision Description** | This Nodal Protocol Revision Request (NPRR) implements a Residential Demand Response (RDR) Program for Retail Electric Providers (REPs) and Non-Opt-In Entities (NOIEs).  |
| **Reason for Revision** |  Strategic Plan Objective 1 – Be an industry leader for grid reliability and resilience Strategic Plan 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 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** | With the anticipated growth in Load in the ERCOT Region, fully utilizing all potential sources of capacity, particularly at times of high Net Load, will be critical for reliability. RDR represents a resource that is not fully enabled and utilized today. The ERCOT RDR Program will expand the utilization of smart devices at households to provide Demand response to assist in meeting the peak system Net Load throughout the year. The RDR Program will offer an incentive payment for REPs and NOIEs (via their Qualified Scheduling Entities (QSEs)) to develop programs to incent RDR at the highest Net Load hours on a Seasonal basis. Enabling greater Demand response supports resiliency and reliability to help the system manage unprecedented Demand growth. |
| **PRS Decision** | On 9/17/25, PRS voted to table NPRR1296 and refer the issue to RMS and WMS. There was one abstention from the Independent Generator (Vistra) Market Segment. All Market Segments participated in the vote. |
| **Summary of PRS Discussion** | On 9/17/25, ERCOT Staff provided an overview of NPRR1296, and Vistra presented the issues raised in the 9/10/25 Vistra comments. Participants noted general support for Demand response, but questioned the impacts of NPRR1296 to the wholesale market, and the lack of specific language requiring payments under NPRR1296 reaching the customer directly, citing other Demand response programs where a customer is paid up-front for participation, either directly or in the form of a bill credit. Some participants expressed support for NPRR1296, at least as a near-term solution, to stimulate residential participation in Demand response while a longer-term market-based approach is discussed and developed by stakeholders. ERCOT Staff noted the predicted payments under NPRR1296 would be on par with similar programs in other markets, and the broad language of NPRR1296 relies on the expertise of Load Serving Entities (LSEs) (and competition between LSEs) to administer the finer details of the program. ERCOT Staff noted the current existence of the market-based Aggregate Distributed Energy Resource (ADER) program and its limited use today. |

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| **Opinions** |
| **Credit Review** | To be determined |
| **Independent Market Monitor Opinion** | To be determined |
| **ERCOT Opinion** | To be determined |
| **ERCOT Market Impact Statement** | To be determined |

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| **Sponsor** |
| **Name** | Ryan King |
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| **Market Segment** | Not applicable |

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| **Market Rules Staff Contact** |
| **Name** | Cory Phillips |
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| **Comments Received** |
| **Comment Author** | **Comment Summary** |
| Vistra 091025 | Opposed NPRR1296 |

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| **Market Rules Notes** |

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

* NPRR1214, Reliability Deployment Price Adder Fix to Provide Locational Price Signals, Reduce Uplift and Risk
	+ Section 9.5.3
* NPRR1235, Dispatchable Reliability Reserve Service as a Stand-Alone Ancillary Service
	+ Section 9.5.3

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| **Proposed Protocol Language Revision** |

**2.1 DEFINITIONS**

**Residential Demand Response (RDR)** **Program**

A program to enable residential Customers with smart responsive appliances or devices to reduce the system Load during peak Net Load hours in exchange for an incentive payment.

**Unique Meter Identifiers (UMIs)**

For Non-Opt-In-Entity (NOIE) areas, the unique identifier assigned to each Service Delivery Point used in the systems managed by ERCOT or another Independent Organization.

**2.2 ACRONYMS AND ABBREVIATIONS**

**RDR** Residential Demand Response

**UMI** Unique Meter Identifier

***3.6.1 Load Resource Participation***

(1) A Load Resource may participate by providing:

(a) Ancillary Service:

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

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

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

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

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

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

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

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

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

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

(d) Voluntary Load response in Real-Time.

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

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

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

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

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

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

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

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

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

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

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

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

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

(a) The ERS Resource and each site within the ERS Resource are not located behind an ESI ID or Unique Meter Identifier (UMI) that corresponds to a Critical Load and are not used to support a Critical Load; or

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

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

**3.7.1.2 Load Resource Parameters**

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

(a) Maximum interruption time;

(b) Maximum daily deployments;

(c) Maximum weekly deployments;

(d) Maximum weekly energy;

(e) Minimum notice time;

(f) Minimum interruption time; and

(g) Minimum restoration time.

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

(a) Normal Ramp Rate curve;

(b) Emergency Ramp Rate curve;

(c) Maximum deployment time; and

(d) Maximum weekly energy.

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

**3.14.3.1 Emergency Response Service Procurement**

(1) ERCOT shall issue Requests for Proposals to procure ERS for each Standard Contract Term. The ERS Standard Contract Terms are as follows:

(a) December through March;

(b) April and May;

(c) June through September; and

(d) October and November.

(2) ERCOT shall procure ERS from one or more of the four following ERS service types:

(a) Weather-Sensitive ERS-10

(b) Non-Weather-Sensitive ERS-10

(c) Weather-Sensitive ERS-30

(d) Non-Weather-Sensitive ERS-30

(3) ERS offers shall be submitted only by QSEs capable of receiving Extensible Markup Language (XML) messaging on behalf of represented ERS Resources.

(4) Each site in an ERS Generator must have an interconnection agreement with its TDSP prior to submitting an ERS offer and must have exported energy to the ERCOT System prior to the offer due date. An ERS Resource that cannot inject energy to the ERCOT System can only be offered as an ERS Load.

(5) In order to qualify as weather-sensitive, an ERS Load must meet one of the following criteria:

(a) The ERS Load must consist exclusively of residential sites; or

(b) The ERS Load must consist exclusively of non-residential sites and must qualify as weather-sensitive based on the accuracy of the regression baseline evaluation methodology as described in Section 8.1.3.1.1, Baselines for Emergency Response Service Loads, as an indicator of actual interval Load.

(i) ERCOT shall establish minimum accuracy standards for qualification as an ERS Load under the regression baseline evaluation methodology.

(ii) An ERS Load must have at least nine months of interval meter data to qualify as weather-sensitive under the regression baseline evaluation methodology.

(iii) ERCOT’s determination that an ERS Load qualifies as a weather-sensitive ERS Load is independent of ERCOT’s determination of which baseline methodologies may be appropriate for purposes of evaluating the ERS Load’s performance.

(c) If a site with Distributed Renewable Generation (DRG) has been designated by the QSE to be evaluated by using its native load, the default baseline analysis shall be performed using the calculated native load.

(6) QSEs representing ERS Resources may submit offers for one or more ERS Time Periods within an ERS Standard Contract Term. ERS Time Periods shall be defined by ERCOT in the RFP for that ERS Standard Contract Term. An ERS offer is specific to an ERS Time Period. In submitting an offer, both the QSE and the ERS Resource are committing to provide ERS for that ERS Time Period if selected.

(7) A QSE may submit separate offers for an ERS Resource to provide any or all of the four ERS service types during the same or different ERS Time Periods in the same ERS Standard Contract Term, but ERCOT shall only award offers for one service type for each ERS Resource.

(8) The minimum capacity offer for an ERS Load on the weather-sensitive baseline is one half (0.5) MW; all other ERS capacity offers will have a minimum amount that may be offered of one-tenth (0.1) MW. ERS Resources may be aggregated to reach this requirement.

(9) Offers from ERS Generators must include self-serve capacity and injection capacity amounts greater than or equal to zero for each ERS Time Period offered.

(10) ERCOT may establish an upper limit, in MWs, on the amount of ERS capacity it will procure for any ERS Time Period in any ERS Standard Contract Term.

(11) A QSE’s offer to provide ERS shall include:

(a) The name of the QSE representing the ERS Resource and the name of an individual authorized by the QSE to represent the QSE and its ERS Resource(s);

(b) The name of an Entity that controls the ERS Resource, and an affirmation that the QSE has obtained written authorization from the Entity to submit ERS offers on its behalf and to represent the Entity in all matters before ERCOT concerning the Entity’s provision of ERS;

(c) Any information or data specified by ERCOT, including access to historical meter data, and affirmation by the QSE that it has obtained written authorization from the controlling Entity of the ERS Resource for the QSE to obtain such data;

(d) Affirmation that the controlling Entity of the ERS Resource has reviewed P.U.C. Subst. R. 25.507, Electric Reliability Council of Texas (ERCOT) Emergency Response Service (ERS), these Protocols and Other Binding Documents relating to the provision of ERS, and has agreed to comply with and be bound by such provisions;

(e) An agreement by the QSE to produce any written authorization or agreement between the QSE and any ERS Resource it represents, as described in this Section, upon request from ERCOT or the PUCT;

(f) Affirmation that no offered capacity from any site in an ERS Resource has been or will be committed to provide any other product, service, or program during any of the hours in the ERS Time Period in the Standard Contract Term for which the offer is submitted.  Such prohibited products, services, or programs include, but are not limited to, Ancillary Services, Security-Constrained Economic Dispatch (SCED), or TDSP standard offer programs. As an exception to the foregoing, a QSE may offer a site to provide ERS for an ERS Time Period in the Standard Contract Term even if the QSE has an offer pending for that same site to serve as an MRA during that ERS Time Period and Standard Contract Term; however, if the site is selected to serve as an MRA it will not be permitted to serve as ERS during any ERS Time Period in the ERS Contract Term in which it is obligated to serve as an MRA;

(g) Affirmation that the QSE and the controlling Entity the ERS Resource are familiar with any applicable federal, state or local environmental regulations that apply to the use of any generator in the provision of ERS, and that the use of such generator(s) to provide of ERS would not violate those regulations. This provision applies to both ERS Generators and to the use of backup generation by ERS Loads; and

(h) Affirmation that each offered ERS Resource satisfies at least one of the conditions set forth in paragraph (9) of Section 3.6.1, Load Resource Participation, and that all of the ERS Resource’s offered Demand response capacity will be available if deployed by ERCOT during an emergency.

(12) Upon request from a QSE, ERCOT shall provide the dates and times for any deployment events or tests of any ERS site during the previous three ERS Standard Contract Terms, provided that the QSE has obtained written authorization from the ERS site to obtain the information from ERCOT. Such QSE requests shall include the following site-specific information: Electric Service Identifier (ESI ID), Unique Meter Identifier (UMI) (if applicable), or, if the site is in a Non-Opt-In Entity (NOIE) area, site name and site address.

(13) Sites associated with a Dynamically Scheduled Resource (DSR) may not participate in ERS. Offers for Resources containing sites associated with a DSR will be rejected by ERCOT. If ERCOT determines that any participating site is associated with a DSR, that site will be treated as removed from the Resource on the date the determination was made. An ERS Resource’s obligation will not change as a result of any such site removal.

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| ***[NPRR1000: Delete item (13) above upon system implementation and renumber accordingly.]*** |

(14) Each offer submitted by a QSE on behalf of an aggregated ERS Load on a weather-sensitive baseline shall include the QSE’s projection of the maximum number of sites in the aggregation during the ERS Standard Contract Term. ERCOT shall review this projection and the information provided regarding the initial size of each aggregated ERS Load and shall reject any offer on behalf of such an ERS Load if the maximum size of the ERS Load projected by the QSE would violate the limits of site participation growth described in paragraph (15) below.

(15) A QSE may modify the population of an aggregated ERS Load on a weather-sensitive baseline once per month during an ERS Standard Contract Term via a process defined by ERCOT. Such adjustments shall be effective on the first day of each month following the first month. A fully validated ERS Offer form must be received by ERCOT no later than seven Business Days prior to the first day of the month for which is intended to be in effect.

(a) During an ERS Standard Contract Term, a QSE may increase the number of sites in an aggregated ERS Load on a weather-sensitive baseline by no more than the greater of the following:

(i) 100% of the initial number of sites; or

(ii) Two MW times the QSE’s projection of the maximum number of sites in the aggregation during the ERS Standard Contract Term, divided by the maximum MW capacity offered for any ERS Time Period for the aggregation.

(b) Any sites added to an ERS Load on a weather-sensitive baseline are subject to the same requirements for historical meter data as the other sites in the aggregation, as described in paragraph (4) of Section 8.1.3.1.1.

(16) For each of the four ERS service types, an ERS Standard Contract Term may consist of a single ERS Contract Period or multiple non-overlapping ERS Contract Periods, as follows:

(a) If no ERS Resources’ obligations are exhausted for an ERS service type during an ERS Contract Period pursuant to Section 3.14.3.3, Emergency Response Service Provision and Technical Requirements, the ERS Contract Period for that ERS service type shall terminate at the end of the last Operating Day of the ERS Standard Contract Term.

(b) If one or more ERS Resources’ obligations in a given ERS service type are exhausted pursuant to Section 3.14.3.3, the ERS Contract Period for that ERS service type shall terminate at the end of the Operating Day during which the exhaustion occurred. However, if ERS Resources participating in a service type remain deployed at the end of that Operating Day, the ERS Contract Period for that ERS service type shall terminate at the end of the Operating Day on which those ERS Resources are recalled.

(c) If an ERS Contract Period terminates as provided in paragraph (b) above, and one or more ERS Resources’ obligations were not exhausted, a new ERS Contract Period for the ERS service type shall begin at hour ending 0100 on the following Operating Day. This new ERS Contract Period shall terminate as provided in this Section.

(d) If ERCOT elects pursuant to paragraph (b) above to renew the obligations of any ERS Resources whose obligations were entirely exhausted, a new ERS Contract Period for the ERS service type shall begin at hour ending 0100 on the Operating Day after ERCOT has notified QSEs that it has elected to renew the obligation. If a new ERS Contract Period was initiated pursuant to paragraph (c) above on an Operating Day prior to ERCOT issuing a notice of renewal under this paragraph, that ERS Contract Period shall terminate at the end of the Operating Day on which ERCOT notified QSEs that the renewal will take place. This new ERS Contract Period shall terminate as provided in this Section.

(17) An ERS Resource currently obligated to provide an ERS service type during an ERS Time Period and ERS Contract Period may be offered to provide service as an MRA during that same ERS Time Period in the ERS Contract Period. If the ERS Resource is selected to provide service as an MRA during an ERS Time Period in the ERS Contract Period in which it is currently obligated to provide an ERS service type, the ERS Contract Period will be terminated for that ERS service type. The ERS Contract Period for that ERS service type shall terminate at the end of the Operating Day that is five days before the first Operating Day the ERS Resource is obligated to provide service under the MRA Agreement. However, if any ERS Resources participating in that ERS service type are currently deployed at the end of the Operating Day the ERS Contract Period is scheduled to terminate, then the ERS Resource’s ERS Contract Period for that ERS service type shall continue until the end of the Operating Day on which all of the ERS Resources participating in that ERS service type have been recalled, at which time the ERS Contract Period will terminate.

(18) ERS Resources shall be obligated in ERS Contract Periods as follows:

(a) Unless an ERS Contract Period is terminated pursuant to paragraph (17) above, for the first ERS Contract Period in an ERS Standard Contract Term, all ERS Resources awarded by ERCOT shall be obligated.

(b) ERS Resources shall be obligated for 24 hours of cumulative deployment time for any ERS Contract Period during the December through March ERS Standard Contract Term. The obligated cumulative deployment time for any ERS Contract Period during all other ERS Standard Contract Terms shall be 12 hours.

(c) For each of any subsequent ERS Contract Periods for a given ERS service type in an ERS Standard Contract Term, any ERS Resource with remaining obligation due to cumulative deployment time of less than the maximum deployment hours specified for the ERS Standard Contract Term in paragraph (b) above at the end of the last ERS Contract Period shall be obligated for only this remaining deployment time in the new ERS Contract Period.

(d) For each of any subsequent ERS Contract Periods in an ERS Standard Contract Term, ERCOT may renew the obligations of certain ERS Resources as follows:

(i) During the offer submission process, QSEs shall designate on the ERS offer form, which is posted on the ERCOT website, whether an ERS Resource elects to participate in renewal ERS Contract Periods (“renewal opt-in”). Except as provided in paragraph (iv) below, this election is irrevocable once the ERS Resource has been committed for an ERS Standard Contract Term.

(ii) If the obligations of one or more ERS Resources are exhausted before the end of an ERS Standard Contract Term, ERCOT shall determine whether to include renewal opt-ins in the subsequent ERS Contract Period. ERCOT may limit any renewal to one or more ERS Time Periods and/or a specified MW quantity in which obligations have been exhausted.

(iii) If ERCOT decides to include renewal opt-ins in a subsequent ERS Contract Period, ERCOT shall promptly notify all ERS QSEs as to the ERS Time Periods and/or any specified MW quantity that it has elected to renew.

(iv) By the end of the second Business Day in any renewal ERS Contract Period, a QSE may revoke the renewal opt-in status of any of its committed ERS Resources for any subsequent ERS Contract Periods within that ERS Standard Contract Term. ERCOT shall develop a method for QSEs to communicate such information.

(v) By the end of the third Business Day in any ERS Contract Period other than the first ERS Contract Period in an ERS Standard Contract Term, ERCOT shall communicate to QSEs a confirmation of the terms of participation for all of their committed ERS Resources.

(19) In any 12-month period beginning on December 1st and ending on November 30th, ERCOT shall not commit dollars toward ERS in excess of the ERS cost cap, except for the purpose of renewing ERS Resource obligations during a period where ERS has been exhausted. ERCOT may determine cost limits for each ERS Standard Contract Term in order to ensure that the ERS cost cap is not exceeded.

(20) If a QSE offers a Weather-Sensitive ERS Load, selects a control group baseline for that ERS Load, and ERCOT determines that the magnitude of the offer relative to the baseline error will prevent accurate determination of the performance, ERCOT shall reject the offer.

(21) ERCOT shall reduce the available expenditure under the ERS cost cap by the value of the amount of ERS Self-Provision. ERCOT shall value ERS Self-Provision at the clearing price multiplied by the total MW of ERS Self-Provision during each relevant ERS Time Period.

(22) ERCOT shall procure ERS Resources for each ERS Time Period using a clearing price. The Emergency Response Service Procurement Methodology, posted on the ERCOT website, is an Other Binding Document that describes the methodology used by ERCOT to procure ERS. ERCOT may consider geographic location and its effect on congestion in making ERS awards. ERCOT may prorate the capacity awarded to an ERS Resource in an ERS Time Period if the capacity offered for that ERS Resource would cost more than the Emergency Response Service Procurement Methodology allows under the time period expenditure limit. Such proration shall only be done if the QSE indicates on its offer for an ERS Resource that the QSE is willing to have the capacity prorated and also has indicated the lowest prorated capacity limit which is acceptable for that ERS Resource. If proration would result in an award below an ERS Resource’s designated prorated capacity limit or below the minimum MW offer applicable to the ERS service type as specified in paragraph (8) above, the offer will not be awarded.

(23) Payments and Self-Provision credits to QSEs representing ERS Resources are subject to adjustments as described in Section 8.1.3.3, Payment Reductions and Suspension of Qualification of Emergency Response Service Resources and/or their Qualified Scheduling Entities. Deployment of ERS Resources will not result in additional payments other than any payment for which the QSE may be eligible through Real-Time energy imbalance or other ERCOT Settlement process.

(24) QSEs representing ERS Resources selected to provide ERS shall execute a Standard Form Emergency Response Service Agreement, as provided in Section 22, Attachment G, Standard Form Emergency Response Service Agreement.

**3.14.3.4 Emergency Response Service Reporting and Market Communications**

(1) ERCOT shall review the effectiveness and benefits of ERS every 12 months from the start of the program year and report its findings to TAC no later than April 15 of each calendar year.

(2) Prior to the start of the first ERS Contract Period in an ERS Standard Contract Term, and no later than the end of the third Business Day following the start of any subsequent ERS Contract Period in an ERS Standard Contract Term, ERCOT shall post on the ERCOT website the number of MW procured per ERS Time Period, the number and type of ERS Resources selected, and the projected total cost of ERS for that ERS Contract Period.

(3) ERCOT shall post the following documents to the MIS Certified Area for each of the four ERS service types:

(a) ERS Award Notification;

(b) ERS Resources Submission Form – Approved;

(c) ERS Resource Event Performance Summary;

(d) ERS Resource Availability Summary;

(e) ERS Test Portfolio;

(f) ERS Resource Test Results;

(g) ERS Pre-populated Resource Identification Forms;

(h) ERS Resource Group Assignments;

(i) ERS Resource Submission Form – Error Reports;

(j) ERS Preliminary Baseline Review Results;

(k) ERS QSE Portfolio Availability Summary;

(l) ERS QSE Portfolio Event Performance Summary;

(m) ERS Meter Data Error Report;

(n) ERS QSE-level Payment Details Report; and

(o) ERS Obligation Report for TDSPs.

(4) At least 24 hours before an ERS Standard Contract Term begins, or within 72 hours after the beginning of a new ERS Contract Period within an ERS Standard Contract Term, ERCOT shall post the information below to the MIS Certified Area for each affected TDSP:

(a) A list of ERS Resources and members of aggregated ERS Resources located in the TDSP’s service area that will be participating in ERS during the upcoming ERS Standard Contract Term;

(b) The name of the QSE representing each ERS Resource;

(c) The ERS service type provided by each ERS Resource for each ERS Time Period;

(d) All applicable ESI IDs or UMI associated with each ERS Resource;

(e) Estimate of the ERS MW obligation by station code for TDSPs in competitive areas;

(f) Estimate of the ERS MW obligation by zip code for TDSPs in NOIE areas; and

(g) The date(s) of the interconnection agreement(s) for each generator in any ERS Generator.

(5) TDSPs shall maintain the confidentiality of the information provided pursuant to paragraph (4) above.

(6) ERCOT shall post to the ERCOT website the following information for each ERS offer 60 days after the first day of the ERS Standard Contract Term:

(a) The name of the QSE submitting the offer;

(b) For each ERS Time Period, the price and quantity offered, or if the offer is for self-provided ERS, the quantity offered and an indication that the MW will be self-provided; and

(c) The ERS service type.

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| ***[NPRR885, NPRR995, NPRR1007, and NPRR1246: Insert applicable portions of Sections 3.14.4 and 3.14.4.1 below upon system implementation for NPRR885 or NPRR995; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007 and NPRR1246:]***3.14.4 Must-Run Alternative Service**3.14.4.1 Overview and Description of MRAs**(1) Subject to approval by the ERCOT Board, ERCOT may procure Must-Run Alternative (MRA) Service as an alternative to contracting with an RMR Unit if ERCOT determines that the MRA Agreement(s) will, in whole or in part, address the reliability need identified in the RMR study in a more cost-effective manner.(2) ERCOT will issue a request for proposal (RFP) to solicit offers from QSEs to provide MRA Service. (a) A QSE may submit an offer in response to the RFP or enter into an MRA Agreement only if it meets all registration and qualification criteria in Section 16.2, Registration and Qualification of Qualified Scheduling Entities. (b) QSEs whose offers for MRA Service are accepted will be paid according to their offers, subject to the terms of the RFP, MRA Agreement and ERCOT Protocols. A clearing price mechanism shall not be used for awarding offers for MRA Service.(c) A QSE may submit more than one offer for MRA Service in response to a single RFP. A QSE may not submit the same MRA or MRA Sites in more than one of its offers. ERCOT may award multiple offers to a QSE, so long as the MRA or MRA Sites in an awarded offer are not included in any other awarded offer. A QSE may condition ERCOT’s acceptance of an offer for a Demand Response MRA on ERCOT’s acceptance of an offer for a co-located Other Generation MRA offer. (d) Demand Response MRAs and Other Generation MRAs, including MRA Sites within aggregated MRAs, that are situated in NOIE service territories, are eligible to provide MRA Service. Any QSE other than the NOIE QSE wishing to represent such MRAs must obtain written authorization allowing the representation from the NOIE in which the MRA is located. This authorization must be signed by an individual with authority to bind the NOIE and must be submitted to ERCOT prior to the submission of an offer in response to the MRA.(3) An MRA may be connected at either transmission or distribution voltage.(4) An MRA offer is ineligible to the extent it offers capacity that was included as a Resource in ERCOT’s RMR analysis or in the Load forecasts from the Steady State Working Group (SSWG) base cases used as the basis for the RMR analysis, as provided for in paragraph (3)(a) of Section 3.14.1.2, ERCOT Evaluation Process.  (5) Each MRA must provide at least five MW of capacity. (6) Eligible MRA resources may include:(a) A proposed Generation Resource or ESR that was not included in the reliability need evaluation pursuant to paragraph (3)(a) of Section 3.14.1.2. (i) Proposed Generation Resources or ESRs must adhere to all interconnection requirements, including the requirements of Planning Guide Section 5, Generator Interconnection or Modification. (ii) If the proposed Generation Resource is an Intermittent Renewable Resource (IRR), the QSE shall provide capacity values based on the Resource’s projected peak average capacity contribution during the MRA Contracted Hours.(b) Proposed capacity additions to existing Generation Resources or ESRs, if the additional capacity was not included in the reliability need evaluation pursuant to paragraph (3)(a) of Section 3.14.1.2. (i) Prior to providing MRA Service, the Resource Entity will be required to modify its Resource Registration information and complete necessary interconnection requirements with respect to this additional capacity.  (ii) If the capacity is being added to an IRR, the QSE shall provide capacity values based on the Resource’s projected peak average capacity contribution during the hours identified during the MRA Contracted Hours.(c) A proposed or existing generator registered, or proposed to be registered, with ERCOT as a Settlement Only Generator (SOG) or as Distributed Generation (DG). If the generator is an intermittent renewable generator, the QSE, when responding to an RFP for MRA Service, shall provide capacity values based on the MRA’s projected peak average capacity contribution during the hours identified in the MRA Contracted Hours.(d) Proposed or existing Demand response assets, which may include Load Resources and ERS Loads. (e) A proposed or existing Energy Storage System (ESS) registered, or proposed to be registered, with ERCOT as a Settlement Only Energy Storage System (SOESS).(7) An MRA must be able to provide power injection or Demand response to the ERCOT System at ERCOT’s discretion during the MRA Contracted Hours.(a) QSE offers in response to an RFP for MRA Service must fully describe all of the MRA’s temporal constraints. (b) For a Demand Response MRA, QSE offers in response to an RFP for MRA Service must include a statement as to whether the offered capacity is a Weather–Sensitive MRA.(8) The QSE representing an MRA must be capable of receiving both VDI and XML instructions.(9) ERCOT will periodically validate an MRA’s telemetry using 15-minute interval meter data.(10) An MRA for which the MRA or every MRA Site, is metered with either an Advanced Meter or an ERCOT-Polled Settlement (EPS) Meter must be available for qualification testing no later than 10 days prior to the first day of the contracted MRA Service.  Other MRAs must be available for qualification testing no later than 45 days prior to the first day of the contracted MRA Service.(11) All MRA Sites within an MRA must be of the same type (i.e., all Generation Resource MRA, ESR MRA, Other Generation MRA, or Demand Response MRA).(12) A QSE representing an MRA shall submit to ERCOT and continuously update an Availability Plan for each MRA Contracted Hour for the current Operating Day and the next six Operating Days.(13) A QSE representing an MRA or MRA Site may not submit DAM Offers, provide an Ancillary Service or carry an ERS responsibility on behalf of any MRA or MRA Site during the MRA Contracted Hours. Demand Response MRAs may not participate in TDSP standard offer programs during any MRA Contracted Hours.(14) A Combined Cycle Train serving as an MRA must be configured as a single Combined Cycle Generation Resource. (15) QSEs representing MRAs shall submit offers using an MRA offer sheet as provided by ERCOT. (16) QSEs must submit the following information for each MRA offer:(a) The capacity, months and hours offered;(b) For an aggregated MRA, the offered capacity allocated to each MRA Site for all months and hours offered;(c) The Resource ID, ESI ID and or UMI associated with the MRA, or in the case of an aggregated MRA, a list of the Resource IDs, ESI IDs and/or UMIs of the offered MRA Sites;(d) The MRA Standby Price, represented in dollars per MW per hour;(e) Required capital expenditure, if any, if the MRA offer is awarded; (f) The MRA Event Deployment Price, in dollars per deployment event, or proxy fuel consumption rate;(g) The ramp period or startup time of the MRA or aggregated MRA;(h) The MRA Variable Price, in dollars per MW per hour, and/or proxy heat rate;(i) The target availability of the MRA or aggregated MRA; and(j) Any additional information required by ERCOT within the RFP.(17) Demand Response MRAs shall not be deployed more than once per Operating Day.(18) Except for a Forced Outage, any Outage of an MRA must be approved by ERCOT. (19) For any MRA that is registered with ERCOT as a Resource, the QSE representing the MRA must be the same as the QSE representing the Resource. |

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| ***[NPRR885: Insert Section 3.14.4.6.3 below upon system implementation:]******3.14.4.6.3 MRA Metering and Metering Data*** (1) Each Demand Response MRA, or each MRA Site within an aggregated Demand Response MRA, must have an ESI ID and dedicated 15-minute Interval Data Recorder (IDR) metering. A Demand Response MRA, or an MRA Site within an aggregated Demand Response MRA, that is located outside of a competitive service area may use a UMI in lieu of an ESI ID. (2) Each Other Generation MRA, or each MRA Site within an aggregated Other Generation MRA, must have an ESI ID and, if applicable, a Resource ID and dedicated 15-minute IDR metering. An Other Generation MRA, or an MRA Site within an aggregated Other Generation MRA, that is located outside of a competitive service area may use UMIs in lieu of the ESI ID and Resource ID.(3) For ESI IDs and Resource IDs situated in either NOIE or competitive choice areas of the ERCOT Region, meter data is stored in the ERCOT systems and will be accessed by ERCOT and used for all performance evaluations.(4) A QSE representing an MRA or MRA Site in a NOIE service territory is responsible for arranging with the NOIE TDSP to provide ERCOT with interval meter data for the MRA or MRA Site in a format prescribed by ERCOT on a monthly basis within 35 days following the end of a calendar month.(5) ERCOT shall use 15-minute interval meter data, adjusted for the deemed actual DLFs, for each Demand Response MRA and each Other Generation MRA for purposes of availability and event performance measurement. (a) The interval meter data for an MRA or MRA Site located in a competitive choice area will be adjusted by the DLFs used for Settlement for that MRA or MRA Site.(b) The interval meter data for an MRA or MRA Site associated with a UMI in a NOIE area will be adjusted based on a NOIE DSP DLF study submitted to ERCOT pursuant to Section 13.3, Distribution Losses. If no such study has been submitted, the interval meter data will not be adjusted for distribution losses. |

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| ***[NPRR885: Insert Section 3.14.4.9 below upon system implementation:]*****3.14.4.9 MRA Reporting to Transmission and/or Distribution Service Providers (TDSPs)**(1) At least 24 hours before the beginning of an MRA Contracted Month, ERCOT shall provide the report described in paragraph (2) below to each TDSP that has a Demand Response MRA or Other Generation MRA within their service area that is providing MRA Service for the MRA Contracted Month.(2) The report will include the following information for each MRA and MRA Site within the TDSP’s service area:(a) The name of the QSE representing each MRA or MRA Site;(b) A list of the Resource IDs, ESI IDs, and UMIs for each MRA or MRA Site;(c) The date of the interconnection agreement for each Resource ID; and(d) For each Operating Hour, the aggregate contracted capacity for all MRAs and MRA Sites within the TDSP’s service area, by station code in competitive areas and by zip code in NOIE areas.(3) Reports provided under this section are Protected Information under Section 1.3.1.1, Items Considered Protected Information. TDSPs shall maintain the confidentiality of the reports.  |

**3.26** **Residential Demand Response Program**

***3.26.1 Overview***

(1) The Residential Demand Response (RDR) Program is a program to incent reduction in residential Demand during high Seasonal Net Load hours. Participation in the RDR Program is voluntary and is open to Retail Electric Providers (REPs), as well as Non-Opt-In Entity (NOIE) Load Serving Entities (LSEs), utilizing smart responsive appliances or devices in residential households. Incentive Payments for Load reductions under the terms of this program shall be made to Qualified Scheduling Entities (QSEs) that are representing the LSEs for the REP/NOIE.

(2) For the purposes of Section 3.26, Residential Demand Response Program, Season or Seasonal refer to the following: Winter months are December, January, and February; Spring months are March, April, and May; Summer months are June, July, August, and September; Fall months are October and November.

***3.26.2 Participation***

(1) REPs that are submitting data to ERCOT to meet the requirements of Section 3.10.7.2.3, Quarterly Residential Demand Response Data Submission, and that opt to have those Electric Service Identifiers (ESI IDs) participate in the RDR Program must notify ERCOT via email to drsurvey@ercot.com to that effect at least 15 Business Days prior to the beginning of a Season as specified in Section 3.26.3, Assessment Periods. REPs will be deemed to continue their participation in the RDR program until they notify ERCOT that they will opt out via email to drsurvey@ercot.com at least 15 Business Days prior to the beginning of a Season as specified in Section 3.26.3.

(2) NOIE LSEs that have residential Customers with smart responsive appliances or devices that opt to have those Customers participate in the RDR Program also must notify ERCOT via email to drsurvey@ercot.com to that effect at least 15 Business Days prior to the beginning of a Season as specified in Section 3.26.3. Participating NOIE LSEs are required to assign Unique Meter Identifiers (UMIs), analogous to ESI IDs, to their Residential Customers and shall include those identifiers in the data that is required to be submitted in conjunction with participation with the RDR Program as specified below in Section 8.1.4.1. NOIE LSE Customer participation is limited to those that were participating in the Program on or before the first day of the assessment period.

(3) REPs and NOIE LSEs that choose to participate in the RDR Program will be required to submit data via the North American Energy Standards Board (NAESB) communications protocols. REPs and NOIE LSEs may make arrangements with another entity to submit the required data.

(4) ESIIDs/UMIs participating in a TDSP’s Standard Offer Load Management Program implemented under P.U.C. Subst. R. 25.181-183, in ERCOT Emergency Reserve Service (ERS) or in the Aggregate Distributed Energy Resource (ADER) Program will not be eligible for compensation in the RDR Program. To that end, Load reductions for ESI IDs or UMIs also participating in the ERS or ADER Programs during the Seasonal assessment period, will accordingly not be included in RDR Program payment calculations. Participants otherwise may be utilized by REPs and NOIEs to provide Load reductions for other purposes.

***3.26.3 Assessment Periods***

(1) ERCOT will determine the highest hourly Net Loads for each of the four Seasons identified below. ERCOT then will calculate the total hourly Load reduction amount for each NOIE/REP’s reported deployments that included some or all of that hour. The highest calculated hourly Load reductions for a NOIE/REP for a Season shall be the basis for calculating the payment made to that NOIE/REP’s QSE for that NOIE/REP. The number of highest Net Load hours and the number of REP Load reduction hours will vary by Season as shown below.

(2) QSE RDR Program performance for each REP/NOIE LSE will be assessed during the following Seasonal periods:

Summer (June – September): highest six Load reduction hours of the highest eight Net Load hours.

Fall (October – November): highest three Load reduction hours of the highest five Net Load hours.

Winter (December – February): highest six Load reduction hours of the highest eight Net Load hours.

Spring (March – May): highest three Load reduction hours of the highest five Net Load hours.

(3) A minimum of 2,000 participants per NOIE/REP representing RDR resources will be required to be eligible for assessment.

(4) RDR performance will be determined using the methodology outlined in Section 8.1.4, Residential Demand Response Performance.

***3.26.4*** ***Residential Demand Response Program Cap***

(1) For each Seasonal period, if the aggregated load reduction across all RDR Program participants during the largest peak Net Load hours as defined in Section 3.26.3 is more than the MWh cap as defined below, the rate used for payment to the QSEs will be reduced as specified in Section 6.9.1, Residential Demand Response Rate.

Residential Demand Response Program cap:

|  |  |
| --- | --- |
| **Season** | **Cap (MWh)** |
| Spring | 1500 |
| Summer | 3000 |
| Fall | 1500 |
| Winter | 3000 |

***3.26.5 Residential Demand Response Program Commencement***

(1) The Residential Demand Response Program will run annually for four Seasons and begin on March 1 and run until the end of February the following year.

(2) At least 30 calendar days prior to each annual RDR Program commencement, ERCOT will issue a Market Notice that will include information pertinent to the program including the Residential Demand Response Rate as determined per Section 6.9.1, Residential Demand Response Rate.

**6.9 Residential Demand Response Program Settlement**

***6.9.1 Residential Demand Response Rate***

(1) The Residential Demand Response Rate for the year shall be calculated as follows:

**RDRR** a **= Min (IRDRR, HRAPNM** a**) / N**

(2) The Residential Demand Response Rate for the Season shall be capped by the program limits as described in Section 3.26.4, Residential Demand Response Program Cap. The Seasonal Residential Demand Response rate shall be calculated as follows:

**CRDRR** s **= [(SRCAP** s**) / Max (SRCAP** s**, RDRTOT** s**)] \* RDRR** a

Where:

RDRTOT s =

The above variables are defined as follows:

|  |  |  |
| --- | --- | --- |
| **Variable** | **Unit** | **Description** |
| RDRR a | $/MWh | *Residential Demand Response Rate* – The Residential Demand Response Rate, before any adjustments made for program limits, for the year *a*. |
| CRDRR s | $/MWh | *Capped Residential Demand Response Rate –* The Residential Demand Response Rate, adjusted for program limits, for the Season *s*. |
| HRAPNM a | $/ MW-Year | *Historical Rolling Average or Peaker Net Margin* – The historical 3-year rolling average of Peaker Net Margin (PNM) for the previous 3 calendar years ending December 31 of the year before the current program year start date of the Residential Demand Response Program Year. |
| RDRTOT s | MWh | *Residential Demand Response Total* – The total ERCOT-wide Demand response for Season *s*. |
| RESDR *q, s* | MWh | *Residential Demand Response Quantity per QSE per Season –* The MWh Demand response for QSE *q* for Season *s*. |
| N | None | *Number of events per year –* The total of the largest load reduction hours for the year for the RDR Program as defined in Section 3.26.3, Assessment Periods. |
| SRCAP *s* | MWh | *Seasonal Response Cap –* The MWh cap for RDR for Season *s* as defined in Section 3.26.4, Residential Demand Response Program Cap. |
| IRDRR | $/MW-Year | *Initial Residential Demand Response Rate –* The Residential Demand Response Rate, before comparison to the historical 3-year rolling average of Peaker Net Margin. Value is set to $140,000 $/MW-Year |
| q | None | A QSE.  |
| a | None | The year of the RDR Program, as described in paragraph (1) of Section 3.26.5, Residential Demand Response Program Commencement.  |
| s | None | The Season in the Residential Demand Response Program.  |

***6.9.2 Residential Demand Response Payments***

(1) ERCOT shall pay the QSEs participating in the Residential Demand Response (RDR) Program as follows:

**RDRPAMT  *q, s* = (-1) \* CRDRR *s*\* RESDR *q, s***

 Where:

**RESDR *q, s* = ∑ RESDRLSE *l, q, s***

The above variables are defined as follows:

|  |  |  |
| --- | --- | --- |
| **Variable** | **Unit** | **Description** |
| RDRPAMT  *q, s* | $ | *Residential Demand Response Payment per QSE per Season –* The Residential Demand Response payment to QSE *q* for the Season *s.* |
| CRDRR *s* | $/MWh | *Capped Residential Demand Response Rate per Season –* The Residential Demand Response Rate, adjusted for program limits, for the Season *s*. |
| RESDR *q, s* | MWh | *Residential Demand Response Quantity per QSE per Season–* The MWh demand Response for QSE *q* for Season *s*. |
| RESDRLSE *l, q, s* | MWh | *Residential Demand Response Quantity per QSE per LSE per Season –* The MWh Demand Response for QSE *q*, for LSE *l* and Season *s*. |
| *q* | None | A QSE. |
| *s* | None | The Season in the Residential Demand Response Program.  |
| *l* | None | An LSE. |

***6.9.3 Residential Demand Response Charge***

(1) ERCOT shall allocate the costs for the Residential Demand Response (RDR) Program based on the LRS of each QSE during the Season. A QSE’s LRS for the Season shall be the QSE’s total Load for the Season divided by the total ERCOT Load in the Season. For the first Settlement of the RDR Program, as described in paragraph (1) of Section 9.5.13, Settlement of Residential Demand Response Program, LRS will be calculated using the latest Settlement Load for each Operating Day in the Season. For the resettlement of the RDR Program as described in paragraph (2) of Section 9.5.13, the LRS will be calculated using the true-up Load for each Operating Day in the Season.

(2) ERCOT shall calculate each QSE’s RDR charge as follows:

**LARDRAMT  *q, s* = RDRLRS *q, s*\* RDRPAMTTOT *s***

**Where:**

**RDRPAMTTOT *s* =** **RDRPAMT  *q, s***

The above variables are defined as follows:

|  |  |  |
| --- | --- | --- |
| **Variable** | **Unit** | **Description** |
| LARDRAMT *q, s* | $ | *Load-Allocated Residential Demand Response Amount* *per QSE per Season –* The Residential Demand Response charge for QSE *q* for Season *s.* |
| RDRPAMTTOT *s* | $ | *Residential Demand Response Payment Amount Total per Season –* The total of all Residential Demand Response payments for the Season *s*. |
| RDRPAMT*q, s* | $ | *Residential Demand Response Payment per QSE per Season –* The Residential Demand Response payment to QSE *q* for the Season *s.* |
| RDRLRS *q, s* | None | *Residential Demand Response Load Ratio Share per QSE per Season –* The Residential Demand Response Load Ratio Share for QSE *q* for Season *s*. If the resultant QSE-level share is negative, the QSE’s share will be set to zero and all other QSE shares will be adjusted on a pro rata basis such that the sum of all shares is equal to one. |
| *q* | None | A QSE. |
| *s* | None | The Season in the Residential Demand Response Program.  |

***8.1.4*** ***Residential Demand Response Program Performance***

**8.1.4.1 REP and NOIE LSE Data Submission Requirements for RDR Program Participation**

(1) REPs that opt to participate in the RDR Program, as described in Section 3.26, Residential Demand Response Program, do not have data submission requirements beyond those specified in Section 22, Attachment T, Retail Electric Provider and Transmission and/or Distribution Service Providers Smart Device Demand Response Reporting Requirements.

(2) NOIE LSEs that opt to participate in the RDR Program, as described in Section 3.26, must submit four types of files to ERCOT with the following Report Names: RDRPop, RDRParticipant, RDREvent, and RDRIntervaldata. The file naming convention and file contents are described below:

(a) File Naming Convention: All NOIE files are required to follow the naming convention shown below:

DUNS | ReportName | DateTime | Counter

0000000000000RDRPop20251023113001999.csv

|  |  |  |
| --- | --- | --- |
| **Data Element** | **Comments** | **Format** |
| DUNS | Submitter Data Universal Numbering System (DUNS) Number (DUNS #). | Numeric (9 or 13) |
| ReportName | Report name corresponding to the purpose of the file. | Alphanumeric – length varies |
| DateTime | File transmission date/time stamp. | Datetime format =ccyymmddhhmmss |
| Counter | Counter (optional - may be used by submitter for internal tracking) and included by ERCOT in the names of files sent back to the submitter. | Numeric (3) |
| .csv | Value of CSV mandatory in file name. |  |

(b) Population Data File (Report Name RDRPop)

(i) NOIE LSEs are required to submit an initial Population Data File consisting of all active Residential Customers that were equipped with 15-minute interval metering as of the first day of the Assessment Period. The file must be submitted to ERCOT no later than 15 days after the start of the Assessment Period and must follow the file format and content specifications shown in the table below.

(ii) NOIE LSEs are required to submit a final Population Data File consisting of all active Residential Customers that are equipped with 15-minute interval metering as of the last day of the Assessment Period. The file must be submitted to ERCOT within 15 days after the end of the Assessment Period and must follow the file format and content specifications shown in the table below.

(iii) Note: data elements must be separated with pipes (‘|’) as the delimiter. Three record types are applicable to RDRPop files sent via NAESB: header record; detail record; and summary record. At a minimum the filename must contain .csv after decryption otherwise the file will be rejected by ERCOT. Files must be sent with a NAESB input-format of “FF”. Any file extension other than .csv, such as .xml or .x12 will fail at ERCOT.

(iv) Header Record – One must be present and must be the first record in the file.

| **Data Element** | **Mandatory / Optional** | **Comments** | **Format** |
| --- | --- | --- | --- |
| RecordType | Mandatory | Hard Code “HDR”. | Alpha numeric (3) |
| Report Name | Mandatory | Hard Code “RDRPop”. | Alpha numeric (6) |
| Report ID | Optional | A unique report number designated by the sender to be included in ERCOT produced response and validation files. | Alpha numeric |
| DUNS Number | Mandatory | NOIE DUNS #. | Numeric 1. or 13)
 |

(v) Detail Record - The DET record contains the Unique-Meter-ID-level data information.

| **Data Element** | **Mandatory / Optional** | **Comments** | **Format** |
| --- | --- | --- | --- |
| Record Type | Mandatory | Hard Code “DET”. | Alpha numeric (3) |
| Record Number | Mandatory | A unique sequential record number starting with “1”. | Numeric (8) |
| DUNS Number | Mandatory | NOIE DUNS # associated with the population data sent in the file. | Numeric(9 or 13) |
| Unique Meter ID | Mandatory | The Unique Meter ID is the basic identifier assigned by the NOIE to each SDP. | Alpha numeric (36) |
| Electric Heating | Y/N | Enter ‘Y’ if the primary heating fuel for the home is electricity; otherwise enter ‘N’. If unknown, assign using the methodology described in the ERCOT Current Load Profiling Guide, Appendix D – Profile Decision Tree available on the ERCOT website. | Alpha (1)  |
| On-site Generation | PV/WD/OTH/N | Enter code for type of on-site generation. Enter ‘PV’ if photovoltaic; enter ‘WD’ if wind, enter ‘OTH’ other than photovoltaic or wind or if multiple types of generation are present. Enter ‘N’ if no on-site generation is present. | Alpha (3)  |
| On-site Battery | Y/N | Enter ‘Y’ if a battery is present; otherwise enter ‘N’. | Alpha (1) |
| ZIP Code | Mandatory | Zip code associated with the service delivery point | Numeric (5) |
| Substation Code | Mandatory | Unique code to identify the substation associated with the service delivery point. | Alpha numeric (10) |
| DR Participation | Y/OTH/N | Enter ‘Y’ if the customer is participating in the NOIE LSE RDR Program; Enter ‘OTH’ if the customer is participating in a NOIE DR program other than the RDR Program; otherwise enter ‘N’. | Alpha (3) |

(vi) Summary Record – This record shows the number of DET records in the file.

| **Data Element** | **Mandatory / Optional** | **Comments** | **Format** |
| --- | --- | --- | --- |
| Record Type | Mandatory | Hard Code “SUM”. | Alpha numeric (3) |
| Total Number of DET Records | Mandatory | Total number of DET records, should be equal to the Record Counter in the last DET record. Use zero if no records sent. | Numeric (8) |

(vii) Example RDRPop file

HDR|RDRPop|200608300001||123456789

DET|1|123456789|1001001001001|Y|N|N|12345|ABCDEF|Y

DET|2|123456789|1001001001023| Y|N|N|12345|ABCDEF|Y

DET|3|123456789|1001001001045|20250101| Y|N|N|12345|ABCDEF|N

DET|4|123456789|1001001001045|20250315| Y|N|N|12345|ABCDEF|OTH

SUM|4|

(c) RDR Participant Data File (Report Name RDRParticipant)

(i) NOIE LSEs are required to submit an RDRParticipant Data File consisting of all active Residential Customers that were equipped with 15-minute interval metering and were participating in the RDR Program as of the first day of the Assessment Period. The file must be submitted to ERCOT within 45 days after the end of the Assessment Period and must follow the file format and content specifications shown in the table below.

(ii) Note: data elements must be separated with pipes (‘|’) as the delimiter. Three record types are applicable to RDRParticipant files sent via NAESB: header record; detail record; and summary record. At a minimum the filename must contain .csv after decryption otherwise the file will be rejected by ERCOT. Files must be sent with a NAESB input-format of “FF”. Any file extension other than .csv, such as .xml or .x12 will fail at ERCOT.

(iii) Header Record – One must be present and must be the first record in the file.

| **Data Element** | **Mandatory / Optional** | **Comments** | **Format** |
| --- | --- | --- | --- |
| RecordType | Mandatory | Hard Code “HDR”. | Alpha numeric (3) |
| Report Name | Mandatory | Hard Code “RDRParticipant”. | Alpha numeric (14) |
| Report ID | Optional | A unique report number designated by the sender to be included in ERCOT produced response and validation files. | Alpha numeric |
| DUNS Number | Mandatory | NOIE DUNS #. | Numeric 1. or 13)
 |

(iv) Detail Record - The DET record contains the Unique-Meter-ID-level data information.

|  |  |  |  |
| --- | --- | --- | --- |
| **Data Element** | **Mandatory / Optional** | **Comments** | **Format** |
| Record Type | Mandatory | Hard Code “DET”. | Alpha numeric (3) |
| Record Number | Mandatory | A unique sequential record number starting with “1”. | Numeric (8) |
| DUNS Number | Mandatory | NOIE DUNS # associated with the population data sent in the file. | Numeric(9 or 13) |
| Unique Meter ID | Mandatory | The Unique Meter ID is the basic identifier assigned by the NOIE to each SDP. | Alpha numeric (36) |
| Start Date | Mandatory | Enter the later of the first date of the reporting calendar quarter or the date the ESI ID started participation in the responsive device program. | Numeric (8) yyyymmdd |
| Stop Date | Mandatory | Enter the earlier of the last date of the reporting calendar quarter or the date the ESI ID stopped participation in the responsive device program. | Numeric (8) yyyymmdd |

(v) Summary Record – This record shows the number of DET records in the file.

| **Data Element** | **Mandatory / Optional** | **Comments** | **Format** |
| --- | --- | --- | --- |
| Record Type | Mandatory | Hard Code “SUM”. | Alpha numeric (3) |
| Total Number of DET Records | Mandatory | Total number of DET records, should be equal to the Record Counter in the last DET record. Use zero if no records sent. | Numeric (8) |

(vi) Example RDRParticipant file

HDR|RDRParticipant|200608300001||123456789

DET|1|123456789|1001001001001|20250101|20250331

DET|2|123456789|1001001001023|20250101|20250331

DET|3|123456789|1001001001045|20250101|20250228

DET|4|123456789|1001001001045|20250315|20250331

SUM|4|

(d) RDR Event Data File (Report Name RDREvent)

(i) NOIE LSEs are required to submit an RDREvent Data File to send information to ERCOT regarding Unique Meter ID-level deployments in their responsive device programs. Note that separate rows must be submitted for each time a device is deployed for an Unique Meter ID during a single day and must follow the file format and content specifications shown in the table below.

(ii) Note: data elements must be separated with pipes (‘|’) as the delimiter. Three record types are applicable to RDREvent files sent via NAESB: header record; detail record; and summary record. At a minimum the filename must contain .csv after decryption otherwise the file will be rejected by ERCOT. Files must be sent with a NAESB input-format of “FF”. Any file extension other than .csv, such as .xml or .x12 will fail at ERCOT.

(iii) Header Record – One must be present and must be the first record in the file.

| **Data Element** | **Mandatory / Optional** | **Comments** | **Format** |
| --- | --- | --- | --- |
| RecordType | Mandatory | Hard Code “HDR”. | Alpha numeric (3) |
| Report Name | Mandatory | Hard Code “RDREvent”. | Alpha numeric (8) |
| Report ID | Optional | A unique report number designated by the sender to be included in ERCOT produced response and validation files. | Alpha numeric |
| DUNS Number | Mandatory | NOIE DUNS # associated with the population data sent in the file. | Numeric(9 or 13) |

(iv) Detail Record - The DET record contains the ESI ID-level participation date information.

| **Data Element** | **Mandatory / Optional** | **Comments** | **Format** |
| --- | --- | --- | --- |
| Record Type | Mandatory | Hard Code “DET”. | Alpha numeric (3) |
| Record Number | Mandatory | The unique sequential record number starting with “1”. | Numeric (8) |
| DUNS Number | Mandatory | NOIE DUNS # associated with the population data sent in the file. | Numeric(9 or 13) |
| Unique Meter ID | Mandatory | The Unique Meter ID is the basic identifier assigned by the NOIE to each SDP. | Alpha numeric (36) |
| Event Date | Mandatory | The date the Unique Meter ID was deployed for the responsive device program.  | Numeric (8) yyyymmdd |
| Start Time | Mandatory | The time the load reduction event started for the Unique Meter ID.  |  Numeric (4) hhmm |
| Stop Time | Mandatory | The time the load reduction event ended for the Unique Meter ID.  | Numeric (4) hhmm |
| Device Type Code | Mandatory | Code for the type of device deployed. | Alpha numeric (3) |
| Pre-Event | Mandatory | Y or N – did the REP initiate pre-cooling/pre-heating prior to the event. | Alpha numeric (1) |
| Opt-Out | Mandatory | Y or N – did the participant opt out at any time during the event. | Alpha numeric (1) |

(v) Summary Record – This record shows the number of DET records in the file.

| **Data Element** | **Mandatory / Optional** | **Comments** | **Format** |
| --- | --- | --- | --- |
| Record Type | Mandatory | Hard Code “SUM”. | Alpha numeric (3) |
| Total Number of DET Records | Mandatory | Total number of DET records, should be equal to the Record Counter in the last DET record. Use zero if no records sent. | Numeric (8) |

(vi) Example RDREvent file

HDR|RDREvent|200608300001||123456789

DET|1|123456789|1001001001001|20250115|07:23|08:47|TST|N|N

DET|2|123456789|1001001001023|20250301|07:23|08:47|WH|N|N

DET|3|123456789|1001001001045|20250101|07:23|08:47|TST|N|N DET|4|123456789|1001001001045|20250101|07:23|08:47|WH|N|N
 SUM|4|

**Device Type Code Descriptions**

|  |  |
| --- | --- |
| **Device Type Code** | **Description** |
| BAT | Battery |
| EV | Electric Vehicle Charging |
| PP | Pool Pump |
| TST | Thermostat |
| WH | Electric Domestic Water Heater |
| OTH | Other Device Type |

(e) NOIE Interval Data File (Report Name RDRIntervaldata)

(i) NOIE LSEs are required to submit RDRIntervaldata Files for all days in the Assessment Period for RDR Program participants and for other Unique Meter IDs selected by ERCOT from the initial population files submitted by the NOIE LSEs. These other Unique Meter IDs will be used as a pool of candidates from which to select matches for participating sites to be used for baseline estimation purposes. If on-site generation is associated with a Unique Meter ID, data must also be submitted for the export to the grid from that service delivery point. The interval data files may cover one or more days in the Assessment Period and must follow the file format and content specifications shown in the table below.

(ii) Files are limited in size to no more than 50,000 rows. Multiple files may be submitted together and the counter field in the filename may be used to distinguish them from each other. The interval data within the file must be in single UMI-single day groups with the required header rows for each group followed by the interval data rows for the UMI and date.

(iii) Note: data elements must be separated with pipes (‘|’) as the delimiter. Three record types are applicable to RDRIntervaldata files sent via NAESB: header record; detail record; and summary record. At a minimum the filename must contain .csv after decryption otherwise the file will be rejected by ERCOT. Files must be sent with a NAESB input-format of “FF”. Any file extension other than .csv, such as .xml or .x12 will fail at ERCOT.

(iv) Header Record One must be present and must be the first record in the file.

| **Data Element** | **Mandatory / Optional** | **Comments** | **Format** |
| --- | --- | --- | --- |
| Sort Code | Mandatory | Hard Code “00000001”. | Numeric (8) |
| Unique Meter ID | Mandatory | The Unique Meter ID is the basic identifier assigned by the NOIE to each SDP. | Alpha numeric (36) |
| Channel | Mandatory | Hard Code “1” if export and “4” if import. | Numeric (1) |
| Start Time | Mandatory | YYYYMMDD000000Must be valid date and time value must be 000000 | Numeric (14) |
| Stop Time | Mandatory | YYYYMMDD235900Must be valid date and time value must be 235900 | Numeric (14) |
| DST Participation | Mandatory | Hard Code “Y”. | Alphanumeric (1) |
| Record Flag | Mandatory | Use N for new data.Use Y to delete existing data or to indicate no data exists for day. | Alphanumeric (1) |
| Data Element | Mandatory / Optional | Comments | Alphanumeric/Conditional |
| RecordType | Mandatory | Hard Code “HDR”. | Alpha numeric (3) |
| Report Name | Mandatory | Hard Code “Intervaldata”. | Alpha numeric (12) |
| Report ID | Optional | A unique report number designated by the sender to be included in ERCOT produced response and validation files. | Alpha numeric |
| DUNS Number | Mandatory | NOIE DUNS # associated with the population data sent in the file. | Numeric(9 or 13) |

(v) Header Row Two – This header row contains a number of fields not being used that should be left blank.

| **Data Element** | **Mandatory / Optional** | **Comments** | **Format** |
| --- | --- | --- | --- |
| Sort Code | Mandatory | Hard Code “00000002”. | Numeric (8) |
| Meter Start Reading | Leave Blank | Leave Blank | Leave Blank |
| Meter Stop Reading | Leave Blank | Leave Blank | Leave Blank |
| Meter Multiplier | Leave Blank | Leave Blank | Leave Blank |
| Empty value | Leave Blank | Leave Blank | Leave Blank |
| Pulse multiplier | Leave Blank | Leave Blank | Leave Blank |
| Empty value | Leave Blank | Leave Blank | Leave Blank |
| Seconds per Interval | Mandatory | Hard Code “900”. | Numeric (3) |
| Unit of Measure Code | Mandatory | Hard Code “01”. | Numeric (2) |
| Basic Unit Code | Leave Blank | Leave Blank | Leave Blank |
| Time Zones West of GMT | Leave Blank | Leave Blank | Leave Blank |
| Population | Leave Blank | Leave Blank | Leave Blank |
| Weight | Leave Blank | Leave Blank | Leave Blank |
| Time Zone Standard Name | Leave Blank | Leave Blank | Leave Blank |

(vi) Header Row Three - This header row contains a number of fields not being used that should be left blank.

| **Data Element** | **Mandatory / Optional** | **Comments** | **Format** |
| --- | --- | --- | --- |
| Sort Code | Mandatory | Hard Code “00000003”. | Numeric (8) |
| Descriptor | Mandatory | Leave Blank | Leave Blank |

(vii) Header Row Four – This header row contains the timestamp of the read. This value will determine which read will ‘win’ for a day if there are multiple reads.

| **Data Element** | **Mandatory / Optional** | **Comments** | **Format** |
| --- | --- | --- | --- |
| Sort Code | Mandatory | Hard Code “00000004”. | Numeric (8) |
| Timestamp | Mandatory | Timestamp of read. This value will determine which read will ‘win’ for a day if there are multiple reads.YYYYMMDDHHMMSSMM (24-hour) | Numeric (16)  |
| Origin | Mandatory | Hard Code “M”. | Alphanumeric (1) |

(viii) Header Row Thirty – This header row contains a number of fields not being used that should be left blank.

| **Data Element** | **Mandatory / Optional** | **Comments** | **Format** |
| --- | --- | --- | --- |
| Sort Code | Mandatory | Hard Code “00000030”. | Numeric (8) |
| Name Value Pairs | Mandatory | Hard Code “ATTRIBUTEVALUEPAIRS”. | Alphanumeric (19) |
| MRE DUNS Number | Mandatory | MRE DUNS number  | Numeric (9 or 13) |
| Sender DUNS Number | Mandatory | Sender DUNS number | Numeric (9 or 13) |
| ERCOT DUNS Number | Mandatory | 183529049. | Alphanumeric (9) |
| CR DUNS Number | Optional | Leave Blank | Leave Blank |

(ix) Detailed Record Rows 10000000 through 10000024 – Detail rows contain interval data.

| **Data Element** | **Mandatory / Optional** | **Comments** | **Format** |
| --- | --- | --- | --- |
| Sort Code | Mandatory | 10000000 through 10000024Each row must contain four 15-minute interval sets.For a 92 interval day the data records will go through row 22 (10000022).For a 96 interval day the data records will go through row 23 (10000023).For a 100 interval day the data records will go through row 24 (10000024). | Numeric (8) |
| Interval Value | Mandatory | kWh for the interval, maximum of 3 digits to the right of the decimal and must be a positive value | Numeric (10) |
| Status Code | Mandatory | A or EA = Actual, E = Estimate | Alphanumeric (1) |
| Empty Value | Leave Blank | Leave Blank | Leave Blank |
| Interval Value | Mandatory | kWh for the interval, maximum of 3 digits to the right of the decimal and must be a positive value | Numeric (10) |
| Status Code | Mandatory | A or EA = Actual, E = Estimate | Alphanumeric (1) |
| Empty Value | Leave Blank | Leave Blank | Leave Blank |
| Interval Value | Mandatory | kWh for the interval, maximum of 3 digits to the right of the decimal and must be a positive value | Numeric (10) |
| Status Code | Mandatory | A or EA = Actual, E = Estimate | Alphanumeric (1) |
| Empty Value | Leave Blank | Leave Blank | Leave Blank |
| Interval Value | Mandatory | kWh for the interval, maximum of 3 digits to the right of the decimal and must be a positive value | Numeric (10) |
| Status Code | Mandatory | A or EA = Actual, E = Estimate | Alphanumeric (1) |
| Empty Value | Leave Blank | Leave Blank | Leave Blank |

**8.1.4.2 Files Sent from ERCOT to RDR Participating REPs and NOIE LSEs**

(1) ERCOT shall send Response and Validation Files based on REP submissions as described in Section 22, Attachment T, Retail Electric Provider and Transmission and/or Distribution Service Providers Smart Device Demand Response Reporting Requirements.

(2) ERCOT shall send Response and Validation Files based on NOIE RDRParticipant and RDREvent file submissions as described in Section 22, Attachment T, Retail Electric Provider and Transmission and/or Distribution Service Providers Smart Device Demand Response Reporting Requirements. ERCOT shall send Response and Validation Files based on NOIE RDRPop and RDRIntervaldata file submissions as described below:

(a) **RDRPopERCOTResponse<counter> File:**

This file is the initial response from ERCOT back to a NOIE upon receipt of a ‘RDRPop’ file from that NOIE. The file contains information as to the status of the data submitted including any file format or mandatory data element errors. If the submitted file name has a counter appended by the NOIE, the response file will use the same counter. The file formats and field descriptions are as described below.

(i) **Header Record** – One must be present and must be the first record in the file.

| **Data Element** | **Mandatory / Optional** | **Comments** | **Format** |
| --- | --- | --- | --- |
| Record Type | Mandatory | Hard Code “HDR”. | Alpha numeric(3) |
| Report Name | Mandatory | Hard Code “RDRPopERCOTResponse”. | Alpha numeric (27) |
| Original Report ID | Optional | Report ID as sent in the RDRPop file. | Alpha numeric |
| DUNS Number | Mandatory | NOIE DUNS # associated with the population data sent in the file. | Numeric(9 or 13) |

(ii) **ER1 Record** – Used to designate a record with an invalid value or format, with a reference to the record number in the submitted file that contained the error.

| **Data Element** | **Mandatory / Optional** | **Comments** | **Format** |
| --- | --- | --- | --- |
| Record Type | Mandatory | Hard Code “ER1”. | Alpha numeric (3) |
| Record Number | Mandatory | The unique sequential record number starting with “1”. | Numeric (8) |
| Unique Meter ID | Mandatory | The Unique Meter ID is the basic identifier assigned by the NOIE to each SDP. | Alpha numeric (36) |
| Original Record Type | Mandatory | The type of record in error. Valid values are DET, HDR, and SUM. | Alpha numeric (3) |
| Original Record Number | Conditional | Original DET Record Number sent from RDRPop file that is in error. Required if Original Record Type is DET. | Numeric (8) |
| Field Name | Mandatory | Field name in record that is in error. | Alpha numeric (80) |
| Error Description | Mandatory | Description of error. | Alpha numeric (80) |

(iii) **ER2 Record** – Used to designate a record with a missing mandatory field, with a reference to the record number in the submitted file that contained the error.

| **Data Element** | **Mandatory / Optional** | **Comments** | **Format** |
| --- | --- | --- | --- |
| Record Type | Mandatory | Hard Code “ER2”. | Alpha numeric (3) |
| Record Number | Mandatory | The unique sequential record number starting with “1”. | Numeric (8) |
| Unique Meter ID | Mandatory | The Unique Meter ID is the basic identifier assigned by the NOIE to each SDP. | Alpha numeric (36) |
| Original Record Type | Mandatory | The type of record in error. Valid values are DET, HDR, and SUM. | Alpha numeric (3) |
| Original Record Number | Conditional | Original DET Record Number sent from RDRPop file that is in error. Required if Original Record Type is DET. | Numeric (8) |
| Field Name | Mandatory | Field name in record that is in error. | Alpha numeric (80) |
| Error Description | Mandatory | Description of error. | Alpha numeric (80) |

(iv) **Sum Record** – Provides the sum of all records received in the original file, the number of records processed, and the number of DET records in error.

| **Data Element** | **Mandatory / Optional** | **Comments** | **Format** |
| --- | --- | --- | --- |
| Record Type | Mandatory | Hard code “SUM”. | Alpha numeric (3) |
| Total Number of DET Records | Mandatory | Total number of DET records in the original RDRPop file. | Numeric (8) |
| Total Number of Processed DET Records | Mandatory | Total number of DET records processed without error from the RDRPop file. | Numeric (8) |
| Total Number of Error Records | Conditional | Total number of DET records in error. | Numeric (8) |

(v) **Example RDRPopERCOTResponse File:**

HDR|RDRPopERCOTResponse|200608300001|123456789

ER1|1|1001001001001|DET|1|ElectricHeating|InvalidValue

SUM|5|4|1|

(b)  **RDRPopERCOTValidation File:**

This file type is not in use; ERCOT does not perform any additional business validations for NOIE Population files.

(c) **RDRIntervaldataERCOTResponse<counter> File:**

This file is the initial response from ERCOT back to a NOIE upon receipt of a ‘RDRIntervaldata’ file from that NOIE. The file contains information as to the status of the data submitted including any file format or mandatory data element errors. If the submitted file name has a counter appended by the NOIE, the response file will use the same counter. The file formats and field descriptions are as described below. This file will be posted on MIS Certified Area and will be accessible to the submitter.

(i) **Header Record** – One must be present and must be the first record in the file.

| **Data Element** | **Mandatory / Optional** | **Comments** | **Format** |
| --- | --- | --- | --- |
| Record Type | Mandatory | Hard Code “HDR”. | Alpha numeric(3) |
| Report Name | Mandatory | Hard Code “RDRIntervaldataERCOTResponse”. | Alpha numeric (27) |
| Original Report ID | Optional | Report ID as sent in the RDRIntervaldata file. | Alpha numeric |
| DUNS Number | Mandatory | NOIE DUNS # associated with the population data sent in the file. | Numeric(9 or 13) |

(ii) **ER1 Record** – Used to designate a record with an invalid value or format, with a reference to the record number in the submitted file that contained the error.

| **Data Element** | **Mandatory / Optional** | **Comments** | **Format** |
| --- | --- | --- | --- |
| Record Type | Mandatory | Hard Code “ER1”. | Alpha numeric (3) |
| Record Number | Mandatory | The unique sequential record number starting with “1”. | Numeric (8) |
| Unique Meter ID | Mandatory | The Unique Meter ID is the basic identifier assigned by the NOIE to each SDP. | Alpha numeric (36) |
| Original Record Type | Mandatory | The type of record in error. Valid values are DET, HDR, and SUM. | Alpha numeric (3) |
| Original Record Number | Conditional | Original DET Record Number sent from RDRIntervaldata file that is in error. Required if Original Record Type is DET. | Numeric (8) |
| Field Name | Mandatory | Field name in record that is in error. | Alpha numeric (80) |
| Error Description | Mandatory | Description of error. | Alpha numeric (80) |

(iii) **ER2 Record** – Used to designate a record with a missing mandatory field, with a reference to the record number in the submitted file that contained the error.

| **Data Element** | **Mandatory / Optional** | **Comments** | **Format** |
| --- | --- | --- | --- |
| Record Type | Mandatory | Hard Code “ER2”. | Alpha numeric (3) |
| Record Number | Mandatory | The unique sequential record number starting with “1”. | Numeric (8) |
| Unique Meter ID | Mandatory | The Unique Meter ID is the basic identifier assigned by the NOIE to each SDP. | Alpha numeric (36) |
| Original Record Type | Mandatory | The type of record in error. Valid values are DET, HDR, and SUM. | Alpha numeric (3) |
| Original Record Number | Conditional | Original DET Record Number sent from RDRIntervaldata file that is in error. Required if Original Record Type is DET. | Numeric (8) |
| Field Name | Mandatory | Field name in record that is in error. | Alpha numeric (80) |
| Error Description | Mandatory | Description of error. | Alpha numeric (80) |

(iv) **Sum Record** – Provides the sum of all records received in the original file, the number of records processed, and the number of DET records in error.

| **Data Element** | **Mandatory / Optional** | **Comments** | **Format** |
| --- | --- | --- | --- |
| Record Type | Mandatory | Hard code “SUM”. | Alpha numeric (3) |
| Total Number of DET Records | Mandatory | Total number of DET records in the original RDRIntervaldata file. | Numeric (8) |
| Total Number of Processed DET Records | Mandatory | Total number of DET records processed without error from the RDRIntervaldata file. | Numeric (8) |
| Total Number of Error Records | Conditional | Total number of DET records in error. | Numeric (8) |

(v) **Example RDR**Intervaldata**ERCOTResponse File:**

HDR|RDRIntervaldataERCOTResponse|200608300001|123456789

ER1|1|1001001001001|DET|1|Channel|InvalidValue

SUM|5|4|1|

(d) **RDRIntervaldataERCOTValidation<counter> File:**

This file is an additional response from ERCOT back to a NOIE upon receipt of a ‘RDRIntervaldata’ file for which the RDRIntervaldataERCOTResponse file reported no errors. The file contains information as to the status of any business validation errors. If the submitted file name had a counter appended by the NOIE, the validation file will use the same counter. The file formats and field descriptions are as described below. This file will be returned to the NOIE LSE via NAESB.

(A) **Header Record** – One must be present and must be the first record in the file.

| **Data Element** | **Mandatory / Optional** | **Comments** | **Format** |
| --- | --- | --- | --- |
| Record Type | Mandatory | Hard Code “HDR”. | Alpha numeric (3) |
| Report Name | Mandatory | Hard Code “RDRIntervaldataERCOTValidation”. | Alpha numeric (23) |
| Original Report ID | Optional | Report ID as sent in the RDRIntervaldata file. | Alpha numeric |
| DUNS Number | Mandatory | NOIE DUNS # associated with the population data sent in the file. | Numeric(9 or 13) |

(B) **ER3 Record** – Used to designate a record that failed data validation with a reference to the original record in error.

| **Data Element** | **Mandatory / Optional** | **Comments** | **Format** |
| --- | --- | --- | --- |
| Record Type | Mandatory | Hard Code “ER3”. | Alpha numeric (3) |
| Record Number | Mandatory | The unique sequential record number starting with “1”. | Numeric (8) |
| ESI ID Number | Mandatory | The ESI ID is the basic identifier assigned to each SDP. | Alpha numeric (36) |
| Original Record Type | Mandatory | The type of record in error. Valid values are DET, HDR, and SUM. | Alpha numeric (3) |
| Original Record Number | Conditional | Original DET Record Number sent from RDRIntervaldata file that is in error. Required if Original Record Type is DET. | Numeric (8) |
| Field Name | Mandatory | Field name in record that is in error. | Alpha numeric (80) |
| Error Description | Mandatory | Description of error. | Alpha numeric (80) |

(C) **Sum Record** – Used to provide the sum of all records received in the original file, the number of records processed, and the number of DET records in error.

| **Data Element** | **Mandatory / Optional** | **Comments** | **Format** |
| --- | --- | --- | --- |
| Record Type | Mandatory | Hard code “SUM”. | Alpha numeric (3) |
| Total Number of DET Records | Mandatory | Total number of DET records in the original RDRIntervaldata file. | Numeric (8) |
| Total Number of Processed DET Records | Mandatory | Total number of DET records processed without error from the RDRIntervaldata file. | Numeric (8) |
| Total Number of Error Records | Conditional | Total number of DET records in error. | Numeric (8) |

(D) **Error Descriptions (ERCOT to REP -- the ER3 Record) and Common Fixes**

|  |  |  |
| --- | --- | --- |
| **Error Description** | **Long Description** | **Common Fixes** |
| Invalid-UMI | Unique Meter ID is not found in either the RDRParticipant fileor the RDRERCOTMatchSites file. | Check that all significant digits of UMI were entered and none inadvertently set to zero with copying/pasting processes.Check whether the UMI has been omitted from the RDPParticipant file. |

**8.1.4.3 Performance Criteria for REPs and NOIE LSEs Participating in ERCOT’s Residential Demand Response Program**

(1) ERCOT shall use the REP and NOIE LSE data submitted in accordance with Section 8.1.4.1, REP and NOIE Data Submission Requirements for RDR Program Participation, to determine the highest total MWh load reductions that were realized from deployments of their RDR Programs during each of the highest net load hours in a Seasonal Assessment Period as specified in Section 3.26.3, Assessment Periods. If a REP or NOIE LSE issues as recall for a deployment during one of the highest net load hours, any load increase following the recall will be treated as reducing the load reduction for that hour.

(2) ERCOT will calculate the MWh load reduction for each interval of each of the hours specified in Section 3.26.3 as follows:

RESDRDEP *l, s, i*= RDRPBASETOT *l, s, i*- RDRPACTTOT *l, s, i*

Where

RDRPBASETOT *l, s, i* =

RDRPACTTOT *l, s, i* =

The above variables are defined as follows:

|  |  |  |
| --- | --- | --- |
| **Variable** | **Unit** | **Description** |
| RESDRDEP *l, s, i* | MWH | *Residential Demand Response Deployment–*Load Reduction during interval *i* for all deployed participants of LSE *l* for Assessment Season *s*. |
| RDRPBASETOT *l, s, i* | MWH | *Residential Demand Response Program Baseline Total—*The sum across deployed participants *c* for LSE *l* for interval *i* for Assessment Season *s* of the participant baseline MWH values RDRPBASE *c, l, s, i* |
| RDRPACTTOT *l, s, i* | MWH | *Residential Demand Response Program Actual Total –*The sum across deployed participants for LSE *l* for interval *i* for Assessment Season *s* of the participant actual MWH load RDRPACT. |
| RDRPBASE *c, l, s, i* | MWH | *Residential Demand Response Program Base –*The matching sites baseline value for deployed participant *c* for LSE *l* for interval *i* for Assessment Season *s*. |
| RDRPPACT *c, l, s, i* | MWH | *Residential Demand Response Program Actual –*The actual metered import or export values for deployed participant *c* for LSE *l* for interval *i* for Assessment Season *s*. |
| *c* | None | A deployed participant. |
| *i* | None | An interval in that is included in a high net load hour specified in Section 3.26.3 Assessment Periods. |
| *l* | None | An LSE. |
| *s* | None | The Season in the Residential Demand Response (RDR) Program.  |

(3) ERCOT will sum the Residential Demand Response Deployment values calculated in paragraph (2) above across the intervals in a high net Load hour to quantify the Load reduction realized for LSE *l* in Season *s* and identify the hours with the highest hourly Load reductions from among the hours specified for Season *s* in Section 3.26.3, Assessment Periods. The sum of those Load Reduction values for the Season will establish the MWh Demand response for QSE *q*, for LSE *l* and Season *s* value RESDRLSE *l, q, s*.

(4) For purposes of the calculations described above in paragraph (3), if ERCOT finds that data submitted by a REP or NOIE LSE is missing or invalid for a participant that participant will be excluded from the calculations for the Season. If ERCOT finds that data submitted by a REP or NOIE LSE is missing or invalid for a specific deployment event, ERCOT will treat that participant as not being deployed for that event.

(5) For participants with on-site PV and/or wind generation during REP or NOIE LSE deployment events, if ERCOT determines that an increase in the MWh export was realized during an hour, that increase will be added to the load reduction calculated in paragraph (1) above.

(6) For participants with other types of on-site generation, ERCOT will not attempt to quantify changes in export and will not include any such increases in export to the grid in the load reduction calculated in paragraph (1) above.

(7) ERCOT then shall calculate RESDRLSE *l, q, s* values to be used for Settlement purposes as the sum of the MWh load reductions by interval across those hours for the Season for each REP and NOIE LSE.

(8) The RESDRLSE *l, q, s* value calculated by ERCOT will only be recalculated for settlements subsequent to the final settlement for errors in calculation or granted disputes.

(9) ERCOT shall post a report to the MIS Certified Area for each participating REP and NOIE LSE containing the details of the performance during deployment events that are subject to payment for a Season.

**8.1.4.4 Baselines for Residential Demand Response Program**

(1) ERCOT applies a variety of baseline methodologies for Demand response quantification purposes; the methodologies are documented on the ERCOT website at the following URL: <https://www.ercot.com/services/programs/load>. Baseline methodology options for Residential Loads are typically limited to three of those methodologies: Statistical Regression, Control Group, and Matching Sites. For purposes of the RDR Program ERCOT expects to apply the Matching Sites methodology but may consider using the Statistical Regression baseline if deemed by ERCOT to be necessary.

(2) Since the Matching Sites methodology does not produce an inherently unbiased baseline, ERCOT also expects to apply the ‘Event Day Adjustment Methodology’ described in the document cited in paragraph (1) above to further improve the baseline accuracy.

(3) A critical requirement for using the Matching Sites methodology is to ensure that the Sites selected are not participating in programs that result in or encourage changes to the Load shape characteristics on event days. ERCOT expects to accomplish this by using the data submitted by NOIE LSEs and by using data already available in ERCOT systems or from surveys conducted by ERCOT.

(4) Interval-by-interval baseline values will be determined for each deployed ESI ID/Unique Meter Identifier (UMI) for each interval of a deployment that is included in one of the highest Net Load hours in a Seasonal Assessment Period as specified in Section 3.26.3, Assessment Periods.

(5) If ERCOT is unable to find suitable matching sites for a participant or that participant will be excluded from the performance calculations described in Section 8.1.4.3 Performance Criteria for REPs and NOIE LSEs Participating in ERCOT’s Residential Demand Response Program.

***9.5.3 Real-Time Market Settlement Charge Types***

(1) ERCOT shall provide, on each RTM Settlement Statement, the dollar amount for each RTM Settlement charge and payment. The RTM Settlement “Charge Types” are:

(a) Section 5.7.1, RUC Make-Whole Payment;

(b) Section 5.7.2, RUC Clawback Charge;

(c) Section 5.7.3, Payment When ERCOT Decommits a QSE-Committed Resource;

(d) Section 5.7.4.1, RUC Capacity-Short Charge;

(e) Section 5.7.4.2, RUC Make-Whole Uplift Charge;

(f) Section [5.7.5, RUC Clawback Payment](file:///C%3A%5CUsers%5Cwcallender%5CDownloads%5CResidential%20Demand%20Response%20Program%20NPRR%20%28draft%29%20WDC%20edits%20%285%29.docx#_Toc109528011);

(g) Section [5.7.6, RUC Decommitment Charge](file:///C%3A%5CUsers%5Cwcallender%5CDownloads%5CResidential%20Demand%20Response%20Program%20NPRR%20%28draft%29%20WDC%20edits%20%285%29.docx#_Toc109528014);

(h) Section 6.6.3.1, Real-Time Energy Imbalance Payment or Charge at a Resource Node;

(i) Section 6.6.3.2, Real-Time Energy Imbalance Payment or Charge at a Load Zone;

(j) Section 6.6.3.3, Real-Time Energy Imbalance Payment or Charge at a Hub;

(k) Section 6.6.3.4, Real-Time Energy Payment for DC Tie Import;

(l) Section 6.6.3.5, Real-Time Payment for a Block Load Transfer Point;

(m) Section 6.6.3.6, Real-Time High Dispatch Limit Override Energy Payment;

(n) Section 6.6.3.7, Real-Time High Dispatch Limit Override Energy Charge;

(o) Section 6.6.3.8, Real-Time Payment or Charge for Energy from a Settlement Only Distribution Generator (SODG) or a Settlement Only Transmission Generator (SOTG);

(p) Section 6.6.4, Real-Time Congestion Payment or Charge for Self-Schedules;

(q) Section 6.6.5.1.1.1, Base Point Deviation Charge for Over Generation;

(r) Section 6.6.5.1.1.2, Base Point Deviation Charge for Under Generation;

(s) Section 6.6.5.2, IRR Generation Resource Base Point Deviation Charge;

(t) Section 6.6.5.4, Base Point Deviation Payment;

(u) Section 6.6.6.1, RMR Standby Payment;

(v) Section 6.6.6.2, RMR Payment for Energy;

(w) Section 6.6.6.3, RMR Adjustment Charge;

(x) Section 6.6.6.4, RMR Charge for Unexcused Misconduct;

(y) Section 6.6.6.5, RMR Service Charge;

(z) Section 6.6.6.6, Method for Reconciling RMR Actual Eligible Costs, RMR and MRA Contributed Capital Expenditures, and Miscellaneous RMR Incurred Expenses;

(aa) Paragraph (2) of Section 6.6.7.1, Voltage Support Service Payments;

(bb) Paragraph (4) of Section 6.6.7.1;

(cc) Section 6.6.7.2, Voltage Support Charge;

(dd) Section 6.6.8.1, Black Start Hourly Standby Fee Payment;

(ee) Section 6.6.8.2, Black Start Capacity Charge;

(ff) Section 6.6.9.1, Payment for Emergency Power Increase Directed by ERCOT;

(gg) Section 6.6.9.2, Charge for Emergency Power Increases;

(hh) Section 6.6.10, Real-Time Revenue Neutrality Allocation;

(ii) Section 6.6.14.2, Firm Fuel Supply Service Hourly Standby Fee Payment and Fuel Replacement Cost Recovery;

(jj) Section 6.6.14.3, Firm Fuel Supply Service Capacity Charge;

(kk) Paragraph (1)(a) of Section 6.7.1, Payments for Ancillary Service Capacity Sold in a Supplemental Ancillary Services Market (SASM) or Reconfiguration Supplemental Ancillary Services Market (RSASM);

(ll) Paragraph (1)(b) of Section 6.7.1;

(mm) Paragraph (1)(c) of Section 6.7.1;

(nn) Paragraph (1)(d) of Section 6.7.1;

(oo) Paragraph (1)(e) of Section 6.7.1;

(pp) Paragraph (1)(a) of Section 6.7.2, Payments for Ancillary Service Capacity Assigned in Real-Time Operations;

(qq) Paragraph (1)(b) of Section 6.7.2;

(rr) Paragraph (1)(c) of Section 6.7.2;

(ss) Paragraph (1)(a) of Section 6.7.2.1, Charges for Infeasible Ancillary Service Capacity Due to Transmission Constraints;

(tt) Paragraph (1)(b) of Section 6.7.2.1;

(uu) Paragraph (1)(c) of Section 6.7.2.1;

(vv) Paragraph (1)(d) of Section 6.7.2.1;

(ww) Paragraph (1)(e) of Section 6.7.2.1;

(xx) Paragraph (1)(a) of Section 6.7.3, Charges for Ancillary Service Capacity Replaced Due to Failure to Provide;

(yy) Paragraph (1)(b) of Section 6.7.3;

(zz) Paragraph (1)(c) of Section 6.7.3;

(aaa) Paragraph (1)(d) of Section 6.7.3;

(bbb) Paragraph (1)(e) of Section 6.7.3;

(ccc) Paragraph (2) of Section 6.7.4, Adjustments to Cost Allocations for Ancillary Services Procurement;

(ddd) Paragraph (3) of Section 6.7.4;

(eee) Paragraph (4) of Section 6.7.4;

(fff) Paragraph (5) of Section 6.7.4;

(ggg) Paragraph (6) of Section 6.7.4;

(hhh) Paragraph (7) of Section 6.7.5, Real-Time Ancillary Service Imbalance Payment or Charge (Real-Time Ancillary Service Imbalance Amount);

(iii) Paragraph (7) of Section 6.7.5, (Real-Time Reliability Deployment Ancillary Service Imbalance Amount);

(jjj) Paragraph (8) of Section 6.7.5, (Real-Time RUC Ancillary Service Reserve Amount);

(kkk) Paragraph (8) of Section 6.7.5, (Real-Time Reliability Deployment RUC Ancillary Service Reserve Amount);

(lll) Section 6.7.6, Real-Time Ancillary Service Imbalance Revenue Neutrality Allocation (Load-Allocated Ancillary Service Imbalance Revenue Neutrality Amount);

(mmm) Section 6.7.6, (Load-Allocated Reliability Deployment Ancillary Service Imbalance Revenue Neutrality Amount);

(nnn) Section 6.9.2, Residential Demand Response Payments;

(ooo) Section 6.9.3, Residential Demand Response Charge;

(ppp) Section 7.9.2.1, Payments and Charges for PTP Obligations Settled in Real-Time; and

(qqq) Section 9.16.1, ERCOT System Administration Fee.

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| --- |
| ***[NPRR841, NPRR885, NPRR963, NPRR995, NPRR1012, NPRR1014, and NPRR1216: Replace applicable portions of paragraph (1) above with the following upon system implementation for NPRR841, NPRR885, NPRR963, NPRR995, NPRR1014, or NPRR1216 (Phase 2); or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1012:]***(1) ERCOT shall provide, on each RTM Settlement Statement, the dollar amount for each RTM Settlement charge and payment. The RTM Settlement “Charge Types” are:(a) Section 5.7.1, RUC Make-Whole Payment;(b) Section 5.7.2, RUC Clawback Charge;(c) Section 5.7.3, Payment When ERCOT Decommits a QSE-Committed Resource;(d) Section 5.7.4.1, RUC Capacity-Short Charge;(e) Section 5.7.4.2, RUC Make-Whole Uplift Charge;(f) Section [5.7.5, RUC Clawback Payment](#_Toc109528011);(g) Section [5.7.6, RUC Decommitment Charge](#_Toc109528014);(h) Section 6.6.3.1, Real-Time Energy Imbalance Payment or Charge at a Resource Node; (i) Section 6.6.3.2, Real-Time Energy Imbalance Payment or Charge at a Load Zone;(j) Section 6.6.3.3, Real-Time Energy Imbalance Payment or Charge at a Hub;(k) Section 6.6.3.4, Real-Time Energy Payment for DC Tie Import;(l) Section 6.6.3.5, Real-Time Payment for a Block Load Transfer Point;(m) Section 6.6.3.6, Real-Time High Dispatch Limit Override Energy Payment;(n) Section 6.6.3.7, Real-Time High Dispatch Limit Override Energy Charge;(o) Section 6.6.3.8, Real-Time Payment or Charge for Energy from a Settlement Only Distribution Generator (SODG), Settlement Only Transmission Generator (SOTG), Settlement Only Distribution Energy Storage System (SODESS), or Settlement Only Transmission Energy Storage System (SOTESS); (p) Section 6.6.4, Real-Time Congestion Payment or Charge for Self-Schedules;(q) Section 6.6.5.2, Set Point Deviation Charge for Over Generation; (r) Section 6.6.5.2.1, Set Point Deviation Charge for Under Generation; (s) Section 6.6.5.3, Controllable Load Resource Set Point Deviation Charge for Over Consumption; (t) Section 6.6.5.3.1, Controllable Load Resource Set Point Deviation Charge for Under Consumption;(u) Section 6.6.5.4, IRR Generation Resource Set Point Deviation Charge; (v) Section 6.6.5.4, Set Point Deviation Payment;(w) Section 6.6.5.5, Energy Storage Resource Set Point Deviation Charge for Over Performance; (x) Section 6.6.5.5.1, Energy Storage Resource Set Point Deviation Charge for Under Performance; (y) Section 6.6.6.1, RMR Standby Payment;(z) Section 6.6.6.2, RMR Payment for Energy;(aa) Section 6.6.6.3, RMR Adjustment Charge;(bb) Section 6.6.6.4, RMR Charge for Unexcused Misconduct;(cc) Section 6.6.6.5, RMR Service Charge;(dd) Section 6.6.6.6, Method for Reconciling RMR Actual Eligible Costs, RMR and MRA Contributed Capital Expenditures, and Miscellaneous RMR Incurred Expenses;(ee) Section 6.6.6.7, MRA Standby Payment;(ff) Section 6.6.6.8, MRA Contributed Capital Expenditures Payment;(gg) Section 6.6.6.9, MRA Payment for Deployment Event;(hh) Section 6.6.6.10, MRA Variable Payment for Deployment; (ii) Section 6.6.6.11, MRA Charge for Unexcused Misconduct;(jj) Section 6.6.6.12, MRA Service Charge;(kk) Paragraph (3) of Section 6.6.7.1, Voltage Support Service Payments;(ll) Paragraph (5) of Section 6.6.7.1;(mm) Section 6.6.7.2, Voltage Support Charge;(nn) Section 6.6.8.1, Black Start Hourly Standby Fee Payment;(oo) Section 6.6.8.2, Black Start Capacity Charge;(pp) Section 6.6.9.1, Payment for Emergency Operations Settlement;(qq) Section 6.6.9.2, Charge for Emergency Operations Settlement;(rr) Section 6.6.10, Real-Time Revenue Neutrality Allocation;(ss) Section 6.6.11.1, Emergency Response Service Capacity Payments; (tt) Section 6.6.11.2, Emergency Response Service Capacity Charge; (uu) Section 6.6.14.2, Firm Fuel Supply Service Hourly Standby Fee Payment and Fuel Replacement Cost Recovery;(vv) Section 6.6.14.3, Firm Fuel Supply Service Capacity Charge;(ww) Section 6.7.4, Real-Time Settlement for Updated Day-Ahead Market Ancillary Service Obligations;(xx) Section 6.7.5.2, Regulation Up Service Payments and Charges;(yy) Section 6.7.5.3, Regulation Down Service Payments and Charges;(zz) Section 6.7.5.4, Responsive Reserve Payments and Charges;(aaa) Section 6.7.5.5 , Non-Spinning Reserve Service Payments and Charges;(bbb) Section 6.7.5.6 , ERCOT Contingency Reserve Service Payments and Charges;(ccc) Section 6.7.5.7 , Real-Time Derated Ancillary Service Capability Payment;(ddd) Section 6.7.5.8 , Real-Time Derated Ancillary Service Capability Charge;(eee) Section 6.7.6, Real-Time Ancillary Service Revenue Neutrality Allocation;(fff) Section 6.8.2, Recovery of Operating Losses During an LCAP or ECAP Effective Period;(ggg) Section 6.8.3, Charges for Operating Losses During an LCAP or ECAP Effective Period;(hhh) Section 6.9.2, Residential Demand Response Payments; (iii) Section 6.9.3, Residential Demand Response Charge; (jjj) Section 7.9.2.1, Payments and Charges for PTP Obligations Settled in Real-Time; and(kkk) Section 9.16.1, ERCOT System Administration Fee. |

(2) In the event that ERCOT is unable to execute the Day-Ahead Market (DAM), ERCOT shall provide, on each RTM Settlement Statement, the dollar amount for the following RTM Congestion Revenue Right (CRR) Settlement charges and payments:

(a) Section 7.9.2.4, Payments for FGRs in Real-Time; and

(b) Section 7.9.2.5, Payments and Charges for PTP Obligations with Refund in Real-Time.

***9.5.13 Settlement of Residential Demand Response Program***

(1) ERCOT shall post the Settlement for the Residential Demand Response (RDR) Program 35 days after the due date for the quarterly data submissions as described in paragraph (1)(a) in Section 3.10.7.2.3, Quarterly Residential Demand Response Data Submission. If the 35th day is not a Business Day, ERCOT will post the RDR Settlement on the next Business Day thereafter. All disputes for the Settlement of the RDR Seasonal Period are due ten Business Days after the date that the RDR settlement was posted. ERCOT shall resolve any approved disputes upon resettlement of the RDR Seasonal Period, as described in paragraph (2) below.

(2) ERCOT shall post the resettlement for each RDR Seasonal Period on the True-Up Settlement for the Operating Day on which the charge was first settled, as described in paragraph (1) above. RDR disputes filed based on a change in Load after the True-Up Settlement will be approved only if the Qualified Scheduling Entity’s (QSE’s) calculated Load reduction changes by 10% or more. ERCOT shall resolve any approved RDR disputes no later than 30 Business Days after the date that the RDR resettlement was posted.

**ERCOT Nodal Protocols**

**Section 22**

**Attachment O:** **Requirements for
Aggregate Load Resource Participation
in the ERCOT Markets**

**TBD**

**1 Background and Introduction**

Qualification as a Load Resource is a prerequisite for the provision of Demand response in the Ancillary Services markets and Real-Time Energy Market.

This attachment sets forth the detailed requirements for Aggregations of Loads (more than one single Load site) to qualify as Aggregate Load Resources (ALRs) and maintain such qualification, thus becoming eligible to provide Ancillary Services. The attachment is limited to ALR qualification for participation in Security-Constrained Economic Dispatch (SCED) and the provision of Non-Spinning Reserve (Non-Spin).

For purposes of this attachment, the following terminology applies:

* A “Device” refers to an appliance, implement, or instrument under control or otherwise being used to provide Demand response. A Device is always located behind a Premise-level meter.
* A “Resource” or “Aggregation” refers to an ALR, as defined in Section 2, Definitions and Acronyms.
* All references to ALR in this attachment refer to an ALR that is also a Controllable Load Resource.[[1]](#footnote-1)

**2 Telemetry and Metering Requirements**

**A QSE Telemetry**

A Qualified Scheduling Entity (QSE) representing a Load Resource is required to send Resource-level Real-Time telemetry to ERCOT every two seconds per Section 6.5.5.2, Operational Data Requirements; Nodal Operating Guide, Section 7, Telemetry and Communication, and the ERCOT Nodal ICCP Communication Handbook available on the ERCOT website. Telemetered data points are specific to the service being provided and are listed in detail in Section 6.5.5.2.

The relevant telemetry signals shall represent one of the following:

* The sum of the Load of all Premises in the ALR, or
* The sum of the Load of the Devices under control.

**B Premise-Level Interval Metering**

Premises in an ALR are required to have 15-minute interval meter data, whether Electric Service Identifier (ESI ID) data from the competitive choice areas of ERCOT or revenue-quality meter data within a Non Opt-In Entity (NOIE) territory.[[2]](#footnote-2) ERCOT will use this Premise-level interval meter data both as the foundation of the telemetry validation process and for event performance measurement and verification.

Interval meter data must be time-stamped within appropriate standards in correlation with ERCOT 15-minute Settlement clock intervals, and shall be provided to ERCOT for metered sites within the ALR through one of the following methods:

* For ALRs in competitive choice areas of ERCOT, investor-owned Transmission and/or Distribution Service Providers (TDSPs) submit ESI ID-level Interval Data Recorder (IDR) or Advanced Metering Infrastructure (AMI) data via the Texas Standard Electronic Transaction (TX SET) process (for IDR metering) or via the approved file format defined in Retail Market Guide, Section 9, Appendix G, ERCOT Specified File Format for Submission of Interval Data for Advanced Metering Systems, (for AMI metering); or
* For ALRs in a NOIE service area, the NOIE shall submit IDR, AMI, or equivalent Premise-level meter data, associated with a non-Settlement ESI ID or a designated Unique Meter Identifier (UMI). Such meters shall be maintained and read by the NOIE meter-reading entity. The data shall be submitted to ERCOT either via TX SET or in a format and transport method defined by ERCOT no later than 35 days after each corresponding Operating Day.

NOIE Premise-level UMIs must use ESI ID-style nomenclature, in which the NOIE TDSP Department of Energy (DOE) code comprises the first digits of the identifier. The UMI must remain constant in perpetuity at the Premise.

A NOIE meter-reading entity shall validate Premise-level interval meter data; however, any gaps in the data should not be edited or estimated.  ERCOT will not use data with gaps, or data flagged by the NOIE or ERCOT as invalid.

Ongoing telemetry validation and performance measurement and verification are dependent upon a NOIE making timely and accurate Premise-level meter data submissions. Failure to meet the data submission requirements may result in suspension of the ALR’s qualification to participate in SCED and provide Non-Spin. An ALR that has been suspended for this reason may be reinstated only upon successful restoration of accurate and timely meter data submissions.

NOIEs shall archive Premise-level data sufficient to meet these requirements.

**C Statistical Sampling**

If interval metering is not present or accessible for all sites in an ALR, ERCOT, at its discretion, may design a statistical sample consisting of a sufficient number of 15-minute interval-metered Premises to be consistent with industry best practices.[[3]](#footnote-3) ERCOT shall determine the sample size and composition for any statistical sample.

If statistical sampling is employed, the meter-reading entity shall provide at least 270 days of historical Premise-level 15-minute interval data for each Premise in the statistical sample. If 270 days of historical interval data are not available, the meter-reading entity shall provide as much historical data as is available. ERCOT may disqualify an ALR if it determines that the available historical data for a statistical sample is insufficient to create accurate baseline modeling.

To assist in sampling accuracy, the meter-reading entity shall provide at the time of enrollment, for each Premise in the ALR, at least 12 months of historical monthly billing kWh data, and shall provide monthly billing kWh data for each Premise on an ongoing basis. In addition, ERCOT may require the QSE or meter-reading entity to provide attributes, if available, for each Premise, potentially including but not limited to:

* Identification of Transmission Substation and Load point (irrespective of the Load point associated with the ALR in the Network Model);
* House type (e.g., single-family, multi-family, manufactured); and
* Devices subject to control (e.g., AC, heat pump, electric resistance heat, water heater, pool pump).

Submitting Premise attributes may enable ERCOT to create a smaller statistical sample size.

ERCOT will refresh the makeup of a statistical sample periodically based on population changes. In addition, ERCOT may adjust the size of a statistical sample periodically to reflect the percent of valid data being provided. When new Premises are added to a statistical sample, the meter-reading entity shall provide historical data for the new Premises consistent with the enrollment requirements cited in the preceding paragraph.

As a condition for allowing statistical sampling, ERCOT and the meter-reading entity shall establish a mutually agreeable goal of providing universal interval data at a date in the future.

**3 Telemetry Validation**

The objective of ALR telemetry validation is to create an acceptable standard that provides ERCOT operations with assurance that the telemetered values from the QSE provide an accurate representation of the physical Load characteristics of the ALR. This section describes the processes ERCOT will use to conduct qualification testing and validation for QSE telemetry, with the goal of insuring that an ALR’s telemetered data points provide a representation of ALR performance that meets reasonableness criteria consistent with good utility practice.

ERCOT shall validate telemetry data by comparing aggregated Premise-level 15 minute interval data to the ALR-level QSE telemetry signal, using the procedures described here.

**Premise-Level Telemetry**

In a case in which the ALR telemetry values represent the sum of the Load of the ALR member Premises, ERCOT will aggregate (or, in the case of a statistical sample, extrapolate) the Premise-level 15-minute interval meter data to the ALR level and will compare this data to the QSE telemetry values for Net Real Power Consumption, averaged over each 15-minute Settlement interval. ERCOT will conduct this telemetry validation periodically with each test encompassing all 15-minute Settlement intervals during the calendar month being evaluated. The telemetry must validate to the following criteria: for each month being evaluated, 90% of the 15-minute aggregated Net Real Power Consumption values must be within 10% of the resource-level interval meter data.

**Device-Level Telemetry**

In a case in which the ALR telemetry values represent the sum of the Load of the Devices under control, ERCOT will compare aggregated (or extrapolated) Premise-level data to the ALR QSE telemetry values.

As the initial step in validating Device-level ALR telemetry, ERCOT shall compare the telemetered values for Net Real Power Consumption, averaged over each 15-minute interval, to the aggregated (or extrapolated) Premise-level interval-metered Load. The Premise-level metered Load must exceed the Device-level telemetered NPC values for at least 99 percent of all Settlement intervals in the calendar month being evaluated; otherwise, the telemetry will be considered invalid.

As the second step in validating Device-level ALR telemetry, ERCOT shall evaluate changes in the magnitude of telemetered Device-level Load in response to SCED Base Point Instructions or QSE-initiated self-deployment. Such changes in telemetered NPC should be reflected as corresponding changes in the aggregated (or extrapolated) Premise-level interval meter data, as estimated using an applicable ERCOT baseline methodology.[[4]](#footnote-4). ERCOT will conduct this telemetry validation periodically with each test encompassing all 15-minute Settlement intervals during the calendar month being evaluated. The following intervals will be subject to telemetry validation:

* Any intervals in which the ALR was instructed by SCED to reduce its consumption to a level below its Scheduled Power Consumption by a MW value greater than 10% of the difference between its Scheduled Power Consumption and its Low Power Consumption;
* Any intervals in which the ALR was instructed by SCED to increase its consumption to a level greater than 110% of its current Net Real Power Consumption; and
* Any intervals in which the QSE initiated an out-of-market deployment of the ALR and reported the deployment details to ERCOT, unless the QSE has notified ERCOT of a telemetry failure.

The telemetry must validate to the following criteria: for each month being evaluated, in at least 90% of the intervals subject to telemetry validation, the changes to the telemetered Net Real Power Consumption values, averaged over 15-minute intervals, must be within 10% of the corresponding changes to the aggregated (or extrapolated) Premise-level interval meter data. ERCOT will conduct this validation for any ALRs that have a cumulative rolling six-month total of at least 50 intervals subject to validation. For any six-month period in which an ALR has fewer than 50 intervals subject to validation, the ALR shall be exempt from the suspension provisions detailed below.

ERCOT will conduct a telemetry validation test as part of any ALR’s qualification test to provide Non-Spin as follows: for the duration of the specified period of the qualification test, 80% of the 15-minute aggregated Scheduled Power Consumption plus Two (SPC+2) values must be within 10% of the telemetered Net Real Power Consumption values for the corresponding interval.

In addition, ERCOT will perform periodic telemetry validation as follows: on a monthly basis, 80% of the 15-minute aggregated SPC+2 values must be within 10% of the Scheduled Power Consumption values for the corresponding interval.

For a Non-Spin deployment event, ERCOT may compare the telemetered Scheduled Power Consumption and SPC+2 values for each interval of the event to the ERCOT baseline for the interval. If the difference between the ERCOT baseline and both the Scheduled Power Consumption and SPC+2 values is less than or equal to 10%, the telemetry will be deemed valid for that event.

Failure to meet telemetry validation criteria may result in suspension of the ALR’s qualification to participate in SCED and/or provide Non-Spin. An ALR that has been suspended for telemetry validation failure may be reinstated only upon successfully completing a new telemetry validation test as prescribed herein.

No later than April 1 of each year, ERCOT shall submit a report to TAC containing the results of telemetry validation testing for the prior calendar year. The report shall contain, at a minimum:

* The total number of qualified ALRs in the ERCOT Region;
* The number of telemetry validation tests conducted; and
* The number of telemetry validation test failures.

**4 Management of Changes to ALR Populations**

Changing ALR parameters will be managed by the Resource Entity and the QSE using a market interface[[5]](#footnote-5) dedicated to ALR population maintenance.

* ALR parameters will be established in the Network Model by the ALR’s Resource Entity using the approved Resource Registration process. ALRs that are subject to dynamically changing populations should set their Resource Registration data parameters at levels that will accommodate several months of potential growth so as to reduce the need for frequent Resource Registration updates.
* The QSE may add or subtract Premises from an ALR at any time. The QSE shall update appropriate telemetry values when a change is made to the population,
* QSEs shall report to ERCOT its ALR population changes on a monthly basis via the market interface.
	+ The updates shall include start and stop dates for new Premises in the ALR and/or Premises that have left the ALR. If a Premise is vacated, the Stop Date should reflect that date; and if a new customer later moves into that Premise and joins the ALR, a new start date should be used.
	+ In the competitive choice areas, QSEs will manage the ALR population by ESI ID, which ERCOT will then cross-reference to its internal systems. In the NOIE territories, QSEs shall provide UMIs consistent with the requirements detailed elsewhere in this attachment.

**5 Network Modeling**

Opening the ERCOT markets to participation by aggregations of distribution-connected small commercial and residential Loads will require development of alternative Network Modeling provisions. This section of the requirements attachment sets forth the criteria for the initial rollout of those provisions.

The location of a Load Resource in the Network Model is identified in the Resource Asset Code. During the initial phase of ALR participation in the ERCOT markets, membership in an ALR shall be limited to metered Load sites within the same ERCOT Load Zone. Consistent with current practice for distribution-level single-site Load Resources, the TDSP in collaboration with the Resource Entity and ERCOT will assign each ALR to a single Load point in the ERCOT Common Information Model (CIM).  The total Demand response capability of all ALRs assigned to any single Load point shall be capped at 100% of the rating of the Load point. The rating of a Load point is defined as the value estimated by the ERCOT State Estimator for that Load point at the time of the ERCOT historic coincident peak Demand.

In the long-term, ALR participation in the markets may require an ALR to associate with multiple Loads in the ERCOT CIM while preserving the ability of the ERCOT Independent System Operator (ISO) to dispatch Resources for congestion management based on their location. ERCOT will engage with stakeholders during the phase 1 of ALR participation to identify workable options for this phase 2 approach. Because phase 2 will require changes to market rules and potentially Substantive Rules, and is certain to require significant ERCOT system upgrades, ERCOT hereby establishes a set of caps on initial ALR participation. These caps are implemented in order to avoid system degradation (which could occur if large numbers of ALRs begin are participating) and potential challenges to effective congestion management and grid reliability (due to dispersion of participating Loads with insufficient locational specificity). The caps shall be lifted upon development and implementation of phase 2 of the ALR network modeling approach.

* System-wide ALR participation shall be capped at 250 ALRs.
* The combined Demand response capability of all ALRs within any single ERCOT Load Zone shall be capped at 5% of the Load Zone’s highest historic summer peak Demand.

If ERCOT or a TDSP determines that any of the caps described in this section are insufficient to prevent an operational challenge, ERCOT commits to working with stakeholders to determine appropriate changes and seek expedited approval of an amended version of this attachment.

**6 Measurement & Verification**

As part of the qualification process for an ALR to provide Non-Spin, ERCOT will assign the ALR to its appropriate performance evaluation methodology based on an analysis of the ALR’s historical meter data. This process will be similar to the baseline assignment process used by ERCOT in the administration of ERS. In order to qualify to provide Non-Spin, an ALR must be deemed by ERCOT to be eligible for measurement and verification via either the Meter Before/Meter After or Baseline performance evaluation methodologies per Sections 8.1.1.2.1.3, Non-Spinning Reserve Qualification, and 8.1.1.4.3, Non-Spinning Reserve Service Energy Deployment Criteria.

Performance evaluation methodology assignments will depend on the following factors:

* The predictability of the Load as determined through analysis of historical meter data.
* The amount of historical interval meter data available.
* The ability of ERCOT to distinguish between historic event days and non-event days. The QSE shall provide ERCOT with a history of QSE-initiated ALR deployments that are not in response to SCED deployment instructions, including start and stop dates and times for each such QSE-initiated deployment.
* Whether the ALR’s membership is dynamic (subject to migration in either direction) or static.
	+ If the ALR membership is dynamic, the following provisions are in effect:
		- Any ALR consisting entirely of residential sites will be considered eligible for assignment to a Baseline methodology and will retain that designation so long as any sites added to the ALR are residential.
		- An ALR consisting of commercial and industrial sites and also subject to migration will be subject to baseline review by ERCOT any time a site is added. This review provision may be waived by ERCOT if ERCOT, in consultation with the QSE, determines that the added sites meet a uniformity test consistent with the existing sites in the ALR. To avoid ongoing baseline reviews, the ALR should be composed of Loads with similar Load shapes and, depending on the size of the Aggregation, Load magnitude. Uniformity (a.k.a. homogeneity) enables scalable growth, statistical sampling consistent with industry standard Load research practices, and acceptable migration management. ERCOT may revoke an ALR’s Non-Spin qualification if ERCOT determines that the composition of the ALR fails to meet a uniformity standard consistent with good utility practice.
* If the ALR membership is static (not subject to migration), the ALR will retain the performance evaluation methodology assigned at the time of registration and qualification. ERCOT may annually review a static ALR’s Load characteristics to ensure the performance evaluation methodology assignment continues to apply.

ERCOT shall deny Non-Spin qualification for an ALR if it fails to qualify using either the Meter Before/Meter After, or Baseline methodologies. For the latter, ERCOT may evaluate the ALR against any of the four baseline types described in document entitled “Emergency Response Service Default Baseline Methodologies,” available on the ERCOT website.

As described in Section 8.1.1.4.3, the data used for primary measurement and verification of Load Resource performance in a Non-Spin event are the telemetry values for net real power consumption (net power flow), scheduled power consumption, and scheduled power consumption plus two. As a secondary validation step, ERCOT may use interval meter data from the ALR to verify an ALR’s performance in a Non-Spin deployment event. If the interval meter data evaluation indicates that the ALR met its performance obligations in the Non-Spin event, the ALR will be considered in compliance for that event irrespective of the telemetry values. If the interval meter data evaluation indicates that the ALR failed to meet its performance obligations in the Non-Spin event, the ALR will be deemed to have failed to meet its responsibility for that event irrespective of the telemetry values. ERCOT may revoke the ALR’s qualification to provide Non-Spin if the ALR demonstrates a continuing pattern of failure to perform.

1. Load Resource provision of Non-Spin may be provided only by Controllable Load Resources qualified for SCED. [↑](#footnote-ref-1)
2. NOIE Advanced Meter data submission must meet formatting requirements in place for Emergency Response Service (ERS). See document entitled “Interval Data File Format Descriptions” available on the ERCOT website. [↑](#footnote-ref-2)
3. Further explanation of industry best practice can be found in Load Profiling Guide. [↑](#footnote-ref-3)
4. See “Default Baseline Methodologies” document available on the ERCOT website. [↑](#footnote-ref-4)
5. PR 117-01, Requirements for Data Submission to Support Aggregate Load Resource Participation in the ERCOT Markets. [↑](#footnote-ref-5)