Board Report

(a) ERCOT shall issue ECRS deployment Dispatch Instructions, specifying the required MW output, over ICCP for Resources awarded ECRS with a Resource Status of ONSC.

(b) Dispatch Instruction for deployment of energy from Load Resources via electronic Messaging System.

(3) Energy from Resources providing ECRS may also be manually deployed by ERCOT pursuant to Section 6.5.9, Emergency Operations.

(4) ERCOT shall use SCED and Non-Spin as soon as practicable to recover ECRS reserves.

(5) Following a manual ECRS deployment to Load Resources, excluding Controllable Load Resources, or Resources telemetering a Resource Status of ONSC, the QSE's obligation to deliver ECRS remains in effect until ERCOT issues a recall instruction.

(6) For Generation Resources and Controllable Load Resources providing ECRS, Base Points include ECRS energy as well as any other energy dispatched by SCED. A Resource must be able to be fully dispatched by SCED to its ECRS Ancillary Service award within the ten-minute time frame according to its telemetered ramp rate that reflects the Resource's capability of providing ECRS.

(7) Each Resource providing ECRS shall meet the deployment performance requirements specified in Section 8.1.1.4.2, Responsive Reserve Energy Deployment Criteria.

(8) ERCOT shall issue deployment instructions for Load Resources providing ECRS via XML. Such instructions shall contain the MW requested.

(9) To the extent that ERCOT deploys a Load Resource that is not a Controllable Load Resource and that has chosen a block deployment option, ERCOT shall either deploy the entire Ancillary Service award or, if only partial deployment is possible, skip the Load Resource with the block deployment option and proceed to deploy the next available Resource.

(10) ERCOT shall recall deployed ECRS capacity provided from Resource telemetering Resource Status of ONSC once system frequency recovers above 59.98 Hz.

(11) ERCOT shall recall ECRS deployment provided from a Load Resource that is not a Controllable Load Resource once PRC is above a pre-defined threshold, as described in the Operating Guides.

ERCOT Impact Analysis Report

NPRR Number	**1224**	**NPRR Title**	**ECRS Manual Deployment Triggers**
Impact Analysis Date	March 27, 2024		
Estimated Cost/Budgetary Impact	None.		
Estimated Time Requirements	No project required. This Nodal Protocol Revision Request (NPRR) can take effect following Public Utility Commission of Texas (PUCT) approval.		
ERCOT Staffing Impacts (across all areas)	Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	No impacts to ERCOT computer systems.		
ERCOT Business Function Impacts	ERCOT will update its business processes to implement this NPRR.		
Grid Operations & Practices Impacts	No impacts to ERCOT grid operations and practices.		

Evaluation of Interim Solutions or Alternatives for a More Efficient Implementation
None offered.

Comments
None.

Board Report

NPRR Number	1228	NPRR Title	Continued One-Winter Procurements for Firm Fuel Supply Service (FFSS)
Date of Decision	June 18, 2024		
Action	Recommended Approval		
Timeline	Urgent – to implement the modified timeline proposed herein by the August 1, 2024 deadline to issue the Request for Proposal (RFP) for the 2024-25 Firm Fuel Supply Service (FFSS) obligation period.		
Estimated Impacts	Cost/Budgetary: None Project Duration: No project required		
Proposed Effective Date	The first of the month following Public Utility Commission of Texas (PUCT) approval		
Priority and Rank Assigned	Not applicable		
Nodal Protocol Sections Requiring Revision	3.14.5, Firm Fuel Supply Service		
Related Documents Requiring Revision/Related Revision Requests	None		
Revision Description	This Nodal Protocol Revision Request (NPRR) decreases – from two to one – the number of FFSS obligation periods awarded in an FFSS procurement.		
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		

Board Report

	(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	Currently, the Protocols contemplate that awards for FFSS shall cover two obligation periods, which roughly corresponds with two winters. However, the PUCT has historically set budgets for FFSS procurements that covered one obligation period, based on PUCT Staff and Independent Market Monitor (IMM) recommendations. ERCOT asked for PUCT Staff guidance on whether the next FFSS RFP should cover one or two FFSS obligation periods. After consultation with ERCOT and the IMM, PUCT Staff responded with a recommendation that ERCOT continue to procure only one obligation period at a time. PUCT Staff reasoning included that the offer cap for FFSS is set based on the fuel oil index price available at the time PUCT sets the budget parameters, and, currently, there are no reliable and publicly available prices more than six months in the future. Therefore, it would be very challenging to set an offer cap for the procurement 16 months ahead. The PUCT discussed the PUCT Staff's recommendation at an open meeting on April 25, 2024, and indicated they agreed with PUCT Staff's recommendation. This NPRR decreases the number of obligation periods covered in an FFSS procurement from two to one
PRS Decision	On 5/9/24, PRS voted unanimously to grant NPRR1228 Urgent status; to recommend approval of NPRR1228 as submitted; and to forward to TAC NPRR1228 and the 5/2/24 Impact Analysis. All Market Segments participated in the vote.
Summary of PRS Discussion	On 5/9/24, ERCOT Staff provided an overview of NPRR1228.
TAC Decision	On 5/22/24, TAC voted unanimously to recommend approval of NPRR1228 as recommended by PRS in the 5/9/24 PRS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 5/22/24, there was no additional discussion beyond TAC review of the items below.
TAC Review/Justification of Recommendation	☒ Revision Request ties to Reason for Revision as explained in Justification ☒ Impact Analysis reviewed and impacts are justified as explained in Justification ☒ Opinions were reviewed and discussed ☒ Comments were reviewed and discussed (if applicable)

Board Report

	☐ Other: (explain)
ERCOT Board Decision	On 6/18/24, the ERCOT Board voted unanimously to recommend approval of NPRR1228 as recommended by TAC in the 5/22/24 TAC Report.

Opinions	
Credit Review	ERCOT Credit Staff and the Credit Finance Sub Group (CFSG) have reviewed NPRR1228 and do not believe that it requires changes to credit monitoring activity or the calculation of liability.
Independent Market Monitor Opinion	IMM supports approval of NPRR1228.
ERCOT Opinion	ERCOT supports approval of NPRR1228.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1228 and believes the market impact for NPRR1228 codifies within Protocols the current practice in which the PUCT has been setting FFSS procurement budgets for one obligation period at a time. PUCT Staff recommended continuing this practice based on a lack of fuel index pricing covering two FFSS obligation periods.

Sponsor	
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Market Segment	Not applicable

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Comments Received

Board Report

Comment Author	Comment Summary
None	

Market Rules Notes

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

- NPRR1231, FFSS Program Communication Improvements and Additional Clarifications
  - Section 3.14.5

Proposed Protocol Language Revision

3.14.5 Firm Fuel Supply Service

Commented [CP1]: Please note NPRR1231 also proposes revisions to this section.

(1) Each Generation Resource providing or offering to provide Firm Fuel Supply Service (FFSS), including the primary and any alternate Generation Resources identified in the FFSS Offer Submission Form, must meet technical requirements specified in Section 8.1.1, QSE Ancillary Service Performance Standards, and Section 8.1.1.1, Ancillary Service Qualification and Testing.

(2) ERCOT shall issue an RFP by August 1 of each year soliciting offers from QSEs for Generation Resources to provide FFSS. The RFP shall require offers to be submitted on or before September 1 of each year.

(3) QSEs may submit offers individually for one or more Generation Resources to provide FFSS using the FFSS Offer Submission Form posted on the ERCOT website. A QSE may not submit an offer for a given Generation Resource unless it is the QSE designated by the Resource Entity associated with that Generation Resource. ERCOT must evaluate offers using criteria identified in an appendix to the RFP. ERCOT will issue FFSS awards by September 30 and will post the awards to the MIS Certified Area for each QSE that is awarded an FFSS obligation. The posting will include information such as, but not limited to, the identity of the primary Generation Resource and any alternate Generation Resource(s), the FFSS clearing price, the amount of reserved fuel associated with the FFSS award, the MW amount awarded, and the Generation Resource's initial minimum LSL when providing FFSS. The RFP awards shall cover a period beginning November 15 of the year in which the RFP is issued and ending on March 15 of the ~~second calendar~~ year after the year in which the RFP is issued. A QSE may submit an offer for one or more Generation Resources to provide FFSS beginning in the same year the RFP is issued or as otherwise specified in the RFP. An FFSS Resource (FFSSR) shall be considered an FFSSR and is required to provide FFSS from November 15 through March 15 for each year of the awarded FFSS obligation period. ERCOT shall ensure FFSSRs are procured and deployed as necessary to maintain ERCOT System reliability during, or in preparation for, a natural gas curtailment or other fuel supply disruption.

(a) On the FFSS Offer Submission Form, the QSE shall disclose information including, but not limited to, the Generation Resource and any alternate

Generation Resource(s), the amount of reserved fuel offered, the MW available from the capacity offered, an estimate of the time to restock fuel reserves, and each limitation of the offered Generation Resource that could affect the Generation Resource's ability to provide FFSS.

(b) If the QSE offers a Generation Resource as meeting the qualification requirements in paragraph (1)(c) of Section 8.1.1.2.1.6, Firm Fuel Supply Service Resource Qualification, Testing, Decertification, and Recertification, the QSE must submit as part of its offer a certification for the offered Generation Resource. The certification must include:

(i) Certification that the Generation Entity for the Generation Resource (or an Affiliate) has a Firm Transportation Agreement, firm natural gas supply, and contracted or owned storage capacity meeting the qualification requirements in paragraph (1)(c) of Section 8.1.1.2.1.6;

(ii) The following information regarding the Firm Transportation Agreement:

(A) FFSS Qualifying Pipeline name;

(B) Term;

(C) Primary points of receipt and delivery;

(D) Maximum daily contract quantity (in MMBtu);

(E) Shipper of record; and

(F) Whether the Firm Transportation Agreement provides for ratable receipts and deliveries; and

(iii) The following information regarding the storage arrangements:

(A) Storage facility name;

(B) Term of the Firm Gas Storage Agreement (if applicable);

(C) Maximum storage quantity owned or contracted under the Firm Gas Storage Agreement (in MMBtu); and

(D) Maximum daily withdrawal quantity (in MMBtu).

(c) For a Generation Resource to be eligible to receive an FFSS award, the primary Generation Resource and any alternate Generation Resource(s) identified in the FFSS Offer Submission Form shall complete all applicable testing requirements as specified in Section 8.1.1.2.1.6. A QSE representing an FFSSR is allowed to provide the FFSS with an alternate Resource previously approved by ERCOT to replace the FFSSR.

(d) An offer to provide FFSS is an offer to supply an awarded amount of capacity, maintain a sufficient amount of reserved fuel to meet that award for the duration requirement specified in the RFP, and to designate a specific number of emissions hours that will be reserved for the awarded FFSSR in meeting its obligation to perform in the event that FFSS is deployed. Reserved fuel, emissions hours, and other attributes, in excess of what is needed to meet the FFSS obligation can be used at the discretion of the QSE as long as sufficient fuel reserves and emissions hours are maintained for the purposes of ERCOT deployment of FFSS.

(e) Within ten Business Days of issuing FFSS awards, ERCOT will post on the ERCOT website the identity of all Generation Resources that were offered as primary Generation Resources or alternate Generation Resources to provide FFSS for the most recent procurement period, including prices and quantities offered.

(4) The QSE for an FFSSR shall ensure that the Resource is prepared and able to come On-Line or remain On-Line in order to maintain Resource availability in the event of a natural gas curtailment or other fuel supply disruption.

(a) When ERCOT issues a Watch for winter weather, ERCOT will notify all Market Participants, including all QSEs representing FFSSRs, to begin preparation for potential FFSS deployment. Such preparation may include, but is not limited to, circulation of alternate fuel to its facilities, if applicable; heat fuel oil to appropriate temperatures, if applicable; call out additional personnel as necessary, and be ready to receive a Dispatch Instruction to provide FFSS. An FFSSR may begin consuming a minimum amount of alternate fuel to validate it is ready for an FFSS deployment.

(b) In anticipation of or in the event of a natural gas curtailment or other fuel supply disruption to an FFSSR, the QSE shall notify ERCOT as soon as practicable and may request approval to deploy FFSS to generate electricity. ERCOT shall evaluate system conditions and may approve the QSE's request. The QSE shall not deploy the FFSS unless approved by ERCOT. Upon approval to deploy FFSS, ERCOT shall issue an FFSS VDI to the QSE. ERCOT may issue separate VDIs for each Operating Day for each FFSSR that is deployed for FFSS.

(c) In conjunction with a QSE notification under paragraph (b) above, the QSE shall also report to ERCOT any environmental limitations that would impair the ability of the FFSSR to provide FFSS for the required duration of the FFSS award.

(d) ERCOT may issue an FFSS VDI without a request from the QSE, however ERCOT shall not issue an FFSS VDI without evidence of an impending or actual fuel supply disruption affecting the FFSSR.

(e) If the FFSSR is generating at a level above the FFSS MW awarded amount and that level of output cannot be sustained for the required duration of the FFSS award, ERCOT may use a manual High Dispatch Limit (HDL) override to ensure the FFSSR can continue to generate at the FFSS MW award level for the entire FFSS duration requirement specified in the RFP.

(f) The FFSSR shall continuously deploy FFSS to generate electricity until the earlier of (i) the exhaustion of the fuel reserved to generate at the FFSS MW award level for the duration requirement specified in the RFP, including any fuel that was restocked following approval or instruction from ERCOT, (ii) the fuel supply disruption no longer exists, or (iii) ERCOT determines the FFSS deployment is no longer needed. Upon satisfying one of these qualifications, ERCOT shall terminate the VDI and the FFSSR shall not be obligated to continue its FFSS deployment for the remainder of the Watch.

(g) The QSE for the FFSSR is responsible for communicating with the ERCOT control room the anticipated exhaustion of the reserved fuel at least six hours before that anticipated exhaustion and upon the exhaustion of that fuel.

(h) A QSE shall notify the ERCOT control room of the anticipated exhaustion of emissions credits or permit allowances at least six hours before the exhaustion of those credits or allowances. Upon receiving such notification, ERCOT shall modify the VDI so the FFSS deployment is terminated upon exhaustion of those credits or allowances.

(i) Upon deployment or recall of FFSS, ERCOT shall notify all Market Participants that such deployment or recall has been made, including the MW capacity of service deployed or recalled.

(5) Following the deployment of FFSS, the QSE for an FFSSR may request an approval from ERCOT to restock their fuel reserve to restore their ability to generate at the FFSS MW award level for the duration requirement specified in the RFP. Following approval from ERCOT, a QSE must restock their fuel reserve to restore their ability to generate at the FFSS MW award level for the specified duration requirement. In the event ERCOT does not receive the request to restock from a QSE representing an FFSSR, but the QSE no longer has sufficient reserved fuel to generate at the FFSS MW award level for the specified duration requirement, the QSE shall communicate to the ERCOT control room this reduced capability and ERCOT may instruct the QSE to restock the fuel reserve.

(6) For a Resource to be considered as an alternate for providing FFSS, the following requirements must be met. The alternate Resource must:

(a) Be able to provide net real power sufficient to generate at the same FFSS MW award level as the primary Resource for the duration requirement specified in the RFP;

(b) Be a single Generation Resource, as registered with ERCOT; and

(c) Use the same source of fuel reserve for providing FFSS as the primary Resource.

(7) An FFSS Offer Submission Form may have up to three alternate Generation Resources per primary Resource offering to provide FFSS.

(8) For FFSSRs with approved alternate Generation Resources if the FFSSR becomes unavailable, the QSE must:

(a) As soon as practicable, call the ERCOT control room and inform an Operator that the FFSSR will be replaced by one of the alternate Generation Resource, specify which alternate Generation Resource (if multiple alternate Generation Resources have been designated), and provide an estimate of how long the replacement will be in effect;

(b) Update the Availability Plans for these Generation Resources to reflect current operating conditions within 60 minutes after identifying the change in availability of the FFSSR; and

(c) Update the COPs for these Generation Resources within 60 minutes after identifying the change in availability of the FFSSR.

(9) An FFSSR providing BSS must have sufficient fuel reserved to generate at the FFSS MW award level for the duration requirement specified in the RFP in addition to any fuel required for the Generation Resource to meet the contracted BSS obligation. Any remaining fuel reserve in addition to that required for meeting FFSS and BSS obligations can be used at the QSE's discretion.

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

(11) If FFSS is deployed, then ERCOT will provide a report to the TAC or its designated subcommittee within 30 days of the end of the FFSS obligation period. The report must include the Resources deployed and the reason for any deployments.

(12) Any QSE that submits an offer or receives an award for a SWGR to provide FFSS, and the Resource Entity that owns or controls that SWGR, shall:

(a) Not nominate the SWGR to satisfy supply adequacy or capacity planning requirements in any Control Area other than the ERCOT Region during the period of the FFSS obligation; and

(b) Take any further action requested by ERCOT to ensure that ERCOT will be classified as the "Primary Party" for the SWGR under any agreement between ERCOT and another CAO during the period of the FFSS obligation.

(13) On an annual basis after the FFSS season, ERCOT will provide a report separately for the total amounts from Section 6.6.14.1, Firm Fuel Supply Service Fuel Replacement Costs Recovery, and Section 6.6.14.2, Firm Fuel Supply Service Hourly Standby Fee Payment and Fuel Replacement Cost Recovery, to the TAC or its designated subcommittee.

ERCOT Impact Analysis Report

NPRR Number	**1228**	**NPRR Title**	**Continued One-Winter Procurements for Firm Fuel Supply Service (FFSS)**
Impact Analysis Date	May 2, 2024		
Estimated Cost/Budgetary Impact	None.		
Estimated Time Requirements	No project required. This Nodal Protocol Revision Request (NPRR) can take effect following Public Utility Commission of Texas (PUCT) approval.		
ERCOT Staffing Impacts (across all areas)	Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	No impacts to ERCOT computer systems.		
ERCOT Business Function Impacts	ERCOT will update its business processes to implement this NPRR.		
Grid Operations & Practices Impacts	No impacts to ERCOT grid operations and practices.		

Evaluation of Interim Solutions or Alternatives for a More Efficient Implementation
None offered.

Comments
None.

Board Report

NOGRR Number	255	NOGRR Title	High Resolution Data Requirements
Date of Decision	June 18, 2024		
Action	Recommended Approval		
Timeline	Normal		
Estimated Impacts	Cost/Budgetary: None Project Duration: No project required		
Proposed Effective Date	First of the month following Public Utility Commission of Texas (PUCT) approval		
Priority and Rank Assigned	Not applicable		
Nodal Operating Guide Sections Requiring Revision	6.1, Disturbance Monitoring Requirements 6.1.1, Introduction 6.1.1.1, Applicability (new) 6.1.2, Fault Recording and Sequence of Events Recording Equipment 6.1.2.1. Fault Recording Requirements 6.1.2.2 Fault Recording and Sequence of Events Recording Equipment Location Requirements 6.1.2.3, Fault Recording and Sequence of Events Recording Data Requirements 6.1.2.4, Fault Recording and Sequence of Events Recording Data Retention and Reporting Requirements 6.1.3, Phasor Measurement Recording Equipment Including Dynamic Disturbance Recording Equipment 6.1.3.1, Dynamic Disturbance Recording Equipment Requirements (new) 6.1.3.1, Recording and Triggering Requirements 6.1.3.2, Location Requirements 6.1.3.3, Data Recording and Redundancy Requirements 6.1.3.4, Data Retention and Data Reporting Requirements 6.1.3.2, Phasor Measurement Unit Requirements (new) 6.1.3.2.1, Phasor Measurement Unit Recording Requirements (new) 6.1.3.2.2, Phasor Measurement Unit Location Requirements (new) 6.1.3.2.3, Phasor Measurement Unit Data Recording and Redundancy Requirements (new) 6.1.3.2.4, Phasor Measurement Unit Data Retention and Data Reporting Requirements (new) 6.1.4, Fault Recording, Sequence of Events Recording, and Phasor		

	Measurement Unit Requirements for Inverter-Based Resources (IBRs) (new) 6.1.4.1, Fault Recording and Sequence of Events Recording Equipment Requirements (new) 6.1.4.1.1, Sequence of Events Recording Data Requirements (new) 6.1.4.1.2, Fault Recording Data and Triggering Requirements (new) 6.1.4.3, Phasor Measurement Unit Equipment Requirements (new) 6.1.4.4, Data Retention and Data Reporting Requirements of Fault Recording, Sequence of Events Recording, and Phasor Measurement Unit Equipment (new) 6.1.4, Maintenance and Testing Requirements 6.1.5, Equipment Reporting Requirements 6.1.6, Review Process 8, Attachment M, Selecting Buses for Capturing Sequence of Events Recording and Fault Recording Data
Related Documents Requiring Revision/Related Revision Requests	None
Revision Description	This Nodal Operating Guide Revision Request (NOGRR) establishes high resolution data requirements.
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 and/or 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	ERCOT has recently experienced several generation ride-through failure events and model quality issues, highlighting the need for high resolution data to perform model validation and event analysis. The

	resolution of Supervisory Control and Data Acquisition (SCADA) data (4-10 sec) is insufficient and, therefore, ERCOT needs high resolution data to help ensure ERCOT System reliability. The North American Electric Reliability Corporation (NERC) 2022 Odessa Disturbance report highlighted the need for such data and ERCOT has identified several updates to the disturbance monitoring requirements in the Nodal Operating Guide to support this important work. ERCOT proposes restructuring the requirements for clarity and separating Inverter-Based Resource (IBR) requirements from the requirements for other facilities. ERCOT has observed several issues when requesting high resolution data. There have been an unacceptable number of requests in which the Market Participant could not provide important data because recording equipment was either not properly maintained or verified as operational. Thus, ERCOT had no access to valuable data needed to troubleshoot a ride-through failure. In response, ERCOT proposes requirements for equipment maintenance and testing to ensure availability of a minimum level of data. Additionally, there have been multiple instances of Market Participants having no data due to inadequate trigger settings on recording equipment. ERCOT proposes additional clarity and consistency on trigger settings for digital fault recorders, sequence of events recording equipment, dynamic disturbance recording equipment, and phasor measurement units. ERCOT also proposes additional requirements for IBRs aligned with Table 19 in the new Institute of Electrical and Electronics Engineers (IEEE) 2800-2022 Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems ("IEEE 2800-2022 standard") to have consistent specification for new and replaced recording equipment for IBRs. ERCOT proposes new disturbance monitoring requirements for Loads greater than 75 MVA and Load or Generation Resources 20 MVA and above that experience ride-through failures, and new requirements for streaming phasor measurement unit data to ERCOT for certain locations. The proposed revisions will also help ERCOT comply with NERC Reliability Standard PRC-002-4, Disturbance Monitoring and Reporting Requirements, which goes into effect on April 1, 2024.
ROS Decision	On 8/3/23, ROS voted unanimously to table NOGRR255 and refer the issue to the System Protection Working Group (SPWG), the Dynamics Working Group (DWG) and the Inverter-Based Resource

	Working Group (IBRWG). All Market Segments participated in the vote. On 2/1/24, ROS voted to recommend approval of NOGRR255 as amended by the 1/30/24 CEHE comments as revised by ROS. There was one abstention from the Independent Generator (Luminant) Market Segment. All Market Segments participated in the vote. On 3/7/24, ROS voted to endorse and forward to TAC the 2/1/24 ROS Report and 6/29/23 Impact Analysis for NOGRR255. There was one abstention from the Independent Generator (Luminant) Market Segment. All Market Segments participated in the vote.
Summary of ROS Discussion	On 8/3/23, participants discussed that ROS working groups began discussing NOGRR255 before formal assignment, that a special SPWG meeting would be scheduled, and that NERC recently published drafts for updated standards. Participants determined to continue further discussions at fewer working groups with joint meetings to minimize strain on resources. On 2/1/24, participants reviewed desktop edits proposed for the 1/30/24 CEHE comments and discussed whether NOGRR255 should remain tabled for further review by the IBRWG. On 3/7/24, participants reviewed the 6/29/23 Impact Analysis.
TAC Decision	On 3/27/24, TAC voted unanimously to table NOGRR255. All Market Segments participated in the vote. On 4/15/24, TAC voted unanimously to recommend approval of NOGRR255 as recommended by ROS in the 3/7/24 ROS Report as amended by the 4/11/24 Luminant comments. All Market Segments participated in the vote.
Summary of TAC Discussion	On 3/27/24, TAC reviewed the items below. Some participants expressed concern that language bifurcating IBR and non-IBR requirements should be further clarified, and determined to table NOGRR255 for additional comments. On 4/15/24, participants reviewed the 4/11/24 Luminant comments.
TAC Review/Justification of Recommendation	☒ Revision Request ties to Reason for Revision as explained in Justification ☒ Impact Analysis reviewed and impacts are justified as explained in Justification ☒ Opinions were reviewed and discussed

Board Report

	[X] Comments were reviewed and discussed (if applicable) [ ] Other: (explain)
ERCOT Board Decision	On 6/18/24, the ERCOT Board voted unanimously to recommend approval of NOGRR255 as recommended by TAC in the 4/15/24 TAC Report.

Opinions	
Credit Review	Not applicable
Independent Market Monitor Opinion	IMM has no opinion of NOGRR255.
ERCOT Opinion	ERCOT supports approval of NOGRR255.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NOGRR255 and believes it has a positive market impact as it provides ERCOT with high resolution data for model validation and event analysis to ensure ERCOT System reliability, and assists compliance with NERC Reliability Standard PRC-002-4, Disturbance Monitoring and Reporting Requirements, which goes into effect April 1, 2024.

Sponsor	
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Market Segment	Not Applicable

Market Rules Staff Contact	
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Comments Received

Board Report

Comment Author	Comment Summary
Oncor 102723	Proposed changes to triggering requirements; clarified location requirements; addressed implementation schedule for requirements; removed requirements regarding transmission of phasor measurement unit data and recommended a separate revision request; opined that model verification tasks can be completed to a practical extent with currently available telemetered data
ERCOT 110123	Clarified fault recording requirements; added phase under-voltage that would trigger Under-Voltage Load Shed (UVLS); adjusted frequency triggers; modified implementation language; agreed to defer proposed location requirements removed by the 10/27/23 Oncor comments
EDFR 120423	Proposed that IBR units operated prior to January 1, 2017, the IEEE C37.118.1-2005 be used as an alternative to IEEE C37.118.1-2011; recommended that ERCOT prioritize the plant level data over the IBR unit data, and develop a phased-in implementation for sequence of events data recording requirements
SPC and Invenergy 120423	Recommended that NOGRR255 remain tabled until after NERC finalizes PRC-028; proposed excluding IBR units from certain requirements; recommended requiring installation of recording devices and global positioning system-based clocks at the longest feeder, rather than on each feeder; proposed further alignment of record length, clock accuracy, and rolling data retention periods with PRC-028
AEPSC 120423	Proposed revisions to Section 8, Attachment M, to align with PRC-002-4 and PRC-002-5; proposed revisions to implementation timelines and reporting requirements
Tesla 120423	Recommended lowering requirements for IBR unit-level time synchronization and fault record data for Resources installed prior to January 1, 2026; proposed revisions to allow IBR units themselves, rather than external equipment, to meet certain requirements; suggested additional data format Comma Separated Value (CSV)
Engie 120723	Noted limited resources available to complete install work associated with NOGRR255 and NOGRR245, Inverter-Based Resource (IBR) Ride-Through Requirements; expressed concern as particularly challenging the requirement to record fault data from individual IBR units; recommended Request For Information on the ability of existing IBR units to comply without retrofit

APA 122023	Noted that original equipment manufacturers or other software/hardware vendors will have to develop the necessary equipment and software to meet the requirements of NOGRR255 as solutions do not currently exist; recommended NOGRR255 remain tabled to allow for alignment with the final NERC PRC-028 standard
ERCOT 010424	Noted Federal Energy Regulatory Commission (FERC) Order 901, paragraph 85 highlighted the urgency and impact of data contemplated in NOGRR255 and urged its adoption not be delayed; reiterated ERCOT's agreement to defer language regarding certain inverter unit-level requirements in order to advance the remainder of NOGRR255; proposed clarifications and refinements to language proposed in other comments
CEHE 010524	Revised timelines for equipment installation; recommended changes to recording equipment and phasor measurement unit location requirements; and modified trigger criterion
CEHE 013024	Clarified the 1/5/24 CEHE comments
Luminant 032224	Proposed that language that applies generally to both IBRs and traditional generators defer to PRC-002 requirements, and offered revisions; and expressed concern for retroactive requirements
ERCOT 032624	Noted objections to elements of the 3/22/24 Luminant comments and urged TAC to recommend approval of NOGRR255 as recommended by ROS in the 3/7/24 ROS Report
Luminant 041124	Offered compromise language with an intent to reconcile the majority of differences between the 3/22/24 Luminant comments and objections raised in the 3/26/24 ERCOT comments

Market Rules Notes

None

Proposed Guide Language Revision

6.1 Disturbance Monitoring Requirements

(1) Disturbance monitoring equipment includes sequence of events recording equipment, fault recording equipment, dynamic disturbance recording equipment, and phasor measurement units.

(a) Sequence of events equipment includes any device capable of recording circuit breaker position (open/close) or ~~other identified~~binary status points that allows analysis of the root cause of a dynamic disturbance based on the order of occurrence of events.

(b) Fault recording equipment captures data associated with an abnormal event on the system, such as phase-to-phase faults, phase-to-ground faults, etc. and includes digital fault recorders, certain protective relays, fault recording-capable meters, and some dynamic disturbance recording equipment.

(c) Dynamic disturbance recording equipment captures incidents that represent behavior of the power system during dynamic events, such as low frequency oscillations, abnormal under/over frequency, voltage excursions and system-wide transients. Some dynamic disturbance recording equipment can also serve as a phasor measurement unit.

~~(d) Digital fault recorders, at high speed, monitor and record the transient response of the power system and equipment during and just after a system fault or transient disturbance. They are intelligent electronic devices that sample binary data (e.g., harmonics, frequency and voltage levels) during power system transients, using communications to retrieve fault, disturbance and sequence of event records and store that data in a digital format.~~

(d~~e~~) Phasor measurement involves measuring time synchronized phasors, frequency, and rate of change of frequency of the power system with accuracy in the order of one microsecond and is typically performed by a digital relay, fault recording equipment or dedicated phasor measurement unit. ~~Phasor measurement unit constantly record data and periodically overwrite data.~~

6.1.1 Introduction

(1) Disturbance monitoring is necessary to:

(a) Determine performance of the ERCOT System;

(b) Determine effectiveness of protective relaying systems;

(c) Verify ERCOT System models;

(d) Determine causes of ERCOT System disturbances (trips, faults, and protective relay system actions); ~~and~~

(e) Determine causes of Generation Resource and Energy Storage Resource (ESR) ride-through performance failures and loss of Load events; and (f~~e~~) Meet the requirements of North American Reliability Corporation (NERC) Reliability Standards.

(2) To ensure ~~that~~ ERCOT has adequate data ~~is available~~ for these activities, ERCOT establishes the disturbance monitoring requirements and procedures ~~discussed~~ in these Operating Guides ~~have been established by ERCOT~~ for the following:

(a) Fault recording, sequence of events recording, phasor measurement, and dynamic disturbance recording equipment owners~~ in the ERCOT System~~; and

(b) Transmission Service Providers (TSPs) and Resource Entities with equipment for recording Geomagnetic Disturbance (GMD) ~~measurement~~ data, including Geomagnetically-Induced Current (GIC) monitors and/or magnetometers for recording geomagnetic field data~~, installed at their facilities~~.

6.1.1.1 Applicability

(1) Section 6.1.2, Fault Recording and Sequence of Events Recording Equipment, and its subsections apply to all ESRs, all Generation Resource ~~f~~Facilities that are not Inverter-Based Resource (IBR) ~~f~~Facilities, and the interconnecting TSP or Distribution Service Provider (DSP) for such Facilities.

(2) Section 6.1.3, Dynamic Disturbance Recording Equipment Including Phasor Measurement Unit Equipment, and its subsections apply to all ESRs, all Generation Resource ~~f~~Facilities that are not ~~Inverter-Based Resource (~~IBR~~)~~ facilities, and to all TSPs and DSPs.

(3) Section 6.1.4, Fault Recording, Sequence of Events Recording, and Phasor Measurement Unit Requirements for Inverter-Based Resources (IBRs), and its subsections apply to IBR ~~f~~Facilities.

6.1.2 Fault Recording and Sequence of Events Recording Equipment

(1) Fault recording equipment includes digital fault recorders, certain protective relays, ~~and/or~~ meters with fault recording capability~~, and dynamic disturbance recorders recording equipment that~~ meeting~~s~~ the associated requirements in this Section.

(2) Sequence of events recording equipment includes any device capable of recording circuit breaker position (open/close) or other ~~identified status~~binary points ~~that~~ meeting~~s~~ the associated requirements in this Section.

(3) Required fault recording ~~and sequence of events recording equipment~~ and sequence of events recording equipment shall, at a minimum, ~~have a clock source~~

~~that is~~ be time synchronized with a Global Positioning System-based clock, or ERCOT-approved alternative~~, with sub-cycle (+/-21 microsecond) timing accuracy and performance~~ ~~to within +/- 2 milliseconds~~ to within +/- 2 milliseconds of Coordinated Universal Time (UTC), with or without a local time offset for Central Prevailing Time (CPT).

~~(4) Required sequence of events recording equipment shall be time synchronized with a Global Positioning System-based clock, or ERCOT-approved alternative, with +/- 2 millisecond timing accuracy and performance of Coordinated Universal Time (UTC), with or without a local time offset for Central Prevailing Time (CPT).~~

6.1.2.1 Fault Recording Requirements

(1) Fault recording equipment shall meet the following requirements:

(a) Either give continuous fault recording data or ~~T~~triggering for ~~at least~~ the following:

(i) Neutral (residual) overcurrent of 0.2 ~~.02~~ p.u. or less of rated current transformer ~~current transformer~~ secondary current or the equivalent of 200-500A primary current; ~~and~~

(ii) Any ~~P~~phase under-voltage below 0.85 ~~.9~~ p.u. for two cycles or longer; ~~or~~~~or overcurrent~~; any

(iii) ~~(iii)~~ Any ~~P~~phase overcurrent above the equipment's maximum emergency current rating~~;~~, or

~~(iv)~~ ~~P~~protective relay tripping for all protection groups;

(iv~~ii~~~~v~~) ~~Document additional triggers and deviations from these trigger settings when local conditions dictate with the review and approval of Any other trigger criterion (including deviations to the above triggers) based on local conditions as~~ Deviations to the above triggering minimum requirements must be reviewed and approved by ERCOT.

(~~i~~v) Additional triggering beyond the minimums above are allowed and do not require review and approval by ERCOT.

~~(iii) Phase over-voltage greater than 1.1 p.u. for two cycles or longer;~~

~~(iv) Phase overcurrent of 1.5 p.u. or less of rated current transformer secondary current or protective relay tripping for all protection groups;~~

~~(v) Frequency below 59.3 Hz or above 60.6 Hz; and~~

~~(vi) Frequency rate of change for low frequency of -0.08125 Hz/sec or high frequency of 0.125 Hz/sec.~~

(b) Minimum recording rate of 16 samples per cycle; and

(c) A single record or multiple records that include~~:~~

~~(i)~~ ~~A~~ a pre-trigger record length of at least two cycles and a total record length of at least ~~30~~ ~~6030~~60 cycles for the same trigger point.~~; or~~

(i) For existing fault recording equipment installed prior to June 1, 2024 that cannot record a total record length of at least 60 cycles and meet the other recording rate and retention period requirements without upgrading or replacing the equipment, the fault recording equipment must, at a minimum, meet a total record length of at least 30 cycles until such time the facility owner must upgrade or replace the equipment.

~~(ii) At least two cycles of the pre-trigger data, the first three cycles of post-trigger data, and the final cycle of the fault as seen by the fault recorder.~~

6.1.2.2 Fault Recording and Sequence of Events Recording Equipment Location Requirements

(1) The location criteria listed below ~~applies~~ apply to Transmission Facilities operated at or above 100 kV unless otherwise specified. The Facility owner,~~(s), whether a Transmission Facility owner or Generation Resource owner,~~ whether a Transmission Facility owner or Generation Resource owner, shall, as applicable, install fault recording and sequence of events recording equipment at the following ~~Facilities~~locations, at a minimum:

(a) Locations identified by the Transmission Facility owner utilizing the methodology in Section 8, Attachment M, Selecting Buses for Capturing Sequence of Events Recording and Fault Recording Data;

(b) Additional locations selected at the Transmission Facility owner's discretion, utilizing the methodology in Section 8, Attachment M;

(c) ~~ERCOT mandatory fault recording and sequence of events recording~~ ~~l~~Locations operating at or above ~~100~~ 60 kV, as defined below.

(i) Interconnections with ~~non-ERCOT~~ Control Areas ~~(i.e.,~~ outside the ERCOT Region~~)~~;

(ii) Substations where electrical transfers ~~of equipment~~ can be made between the ERCOT Control Area and a ~~non-ERCOT~~ Control Area outside the ERCOT Region;

(iii) ~~At a~~All ~~generating station~~ switchyards owned by ~~serving~~ a Generation Resource or ESR connected to the ERCOT System with an aggregated gross generating nameplate capacity above 100 MVA ~~or at the remote line terminals of each generating station switchyard~~.

(d) For ~~any individual Load consisting of one or more Facilities at a single site with an aggregate peak Demand~~ locations that have~~individual Load greater than or equal to 20 MWMVA that has~~ experienced an abnormal trip or immediate L~~l~~oad ~~reduction~~change greater than or equal to 20 MW (including if caused by a Distribution Generation Resource (DGR), Distribution Energy Storage Resource (DESR), or Settlement Only Distribution Generator (SODG)) ~~distribution connected resources)~~ after a fault:~~, ERCOT may require the installation of fault recording and sequence of events recording equipment and the Transmission Facility owner or Distribution Service Provider (DSP) shall install the fault recording and sequence of events recording equipment at an ERCOT-specified location as soon as practicable but no longer than 18 months after ERCOT notifies the Transmission Facility owner or DSP it must install the equipment; and~~

(i) ERCOT may require the installation of fault recording and sequence of events recording equipment;

(ii) The interconnecting Transmission Service Provider (TSP) or Distribution Service Provider (DSP) shall ~~install the recording equipment'~~ ensure recording equipment is installed;

(iii) A suitable location for the recording equipment will be coordinated between ERCOT and the interconnecting TSP or DSP;

(iv) The recording equipment will be installed as soon as practicable, but no longer than 18 months after ERCOT notifies the TSP or DSP ~~it must~~of the need to install the equipment, unless ERCOT provides an extension; and

(v) If the TSP or DSP determines that the recording equipment installation is infeasible due to engineering, technical or operational reasons, it will provide such rationale to ERCOT ~~for consideration~~.

~~(e) The Transmission Facility owner shall install fault recording equipment for each new individual Load over 75 MVA aggregated at a single site placed into service after January 1, 2023.~~

(e) For any ~~individual~~ Load consisting of one or more Facilities at a single site with an aggregate peak Demand greater than or equal to 75 MW behind one or more ~~common Points of Interconnection (POIs) or~~ Service Delivery Points:

(i) ERCOT may require the installation of fault recording and sequence of events recording equipment;

(ii) The interconnecting TSP or DSP shall ~~install~~ensure the recording equipment is installed;

(iii) A suitable location for the recording equipment will be coordinated between ERCOT and the interconnecting TSP or DSP;

(iv) The recording equipment will be installed as soon as practicable, but no longer than 18 months after ERCOT notifies the TSP or DSP ~~it must~~ of the need to install the equipment, unless ERCOT provides an extension; and

(v) If the TSP or DSP determines that the recording equipment installation is infeasible due to engineering, technical or operational reasons, it will provide such rationale in writing to ERCOT ~~for consideration~~.

(2) ~~By December 31, 2024,~~ Transmission Facility owners or Generation Facility owners shall install ~~at least 50% of~~ the ~~new~~ applicable fault recording and sequence of events recording equipment identified in paragraph (1) above as soon as practicable~~such that half of the identified facilities have the associated equipment installed by July 1, 2020, and all 100% of the fault recording and sequence of events recording equipment by December 31, 2025identified facilities by July 1, 2022~~.

[NOGRR255: Replace paragraph (2) above with the following no earlier than <Insert Date at least ~~18 months~~~~three~~two ~~calendar~~ years after PUCT approval> and renumber accordingly:]

(2) Facility owners shall have at least 50% of the new fault recording and sequence of events recording equipment identified in paragraph (1) above installed.

[NOGRR255: Delete paragraph (2) no earlier than <Insert Date at least ~~36~~

~~months~~~~five~~four ~~calendar~~ years after PUCT approval> and renumber accordingly:]

~~(3) For any Generation Resource or ESR that has experienced an abnormal trip or power reduction after a fault, ERCOT may require the installation of fault recording and sequence of events recording equipment and the Resource Facility owner shall install the fault recording and sequence of events recording equipment at an ERCOT-specified location as soon as practicable but no longer than 18 months after ERCOT notifies the Facility owner it must install the equipment, unless the requestor provides and extension.~~

(3) For any Generation Resource or ESR that has not installed fault recording or sequence of events recording equipment and experiences an unexpected trip or significant reduction in output in response to a system disturbance after a fault for which it is unable to determine the cause, ERCOT may require the installation of fault recording and sequence of events recording equipment consistent with the requirements of Section 6.1.2, Fault Recording and Sequence of Events Recording Equipment. The Generation Resource or ESR owner shall install the fault recording and sequence of events recording equipment at an ERCOT-specified location as soon as practicable but no longer than 18 months after the date that ERCOT notifies the Facility owner it must install the equipment, unless the requestor provides an extension.

~~(4) For any identified location requiring fault recording and/or sequence of events recording where the Facility to be monitored (line, transformer, circuit breaker, bus, etc.) is owned by another Entity, and the identifying Facility owner is not recording the required data, then:~~

~~(a) The identifying Facility owner shall notify the other Facility owner of the requirement to monitor that Facility within 90 calendar days of finalizing the list of locations to be monitored; and~~

~~(b) The notified Facility owner shall have three~~~~two~~ ~~calendar years from the notification date to install the required monitoring equipment.~~

6.1.2.3 Fault Recording and Sequence of Events Recording Data Requirements

(1) Each Transmission Facility owner and Generation Resource owner shall have fault recording data to determine the following electrical quantities for each triggered fault recording for the locations specified in Section 6.1.2.2, Fault Recording and Sequence of Events Recording Equipment Location Requirements ~~Transmission Elements operated at or above 100kV it owns connected to the Facilities operated at or above 100kV identified in these requirements~~:

(a) Phase-to-neutral voltage for each phase of each specified bus with ~~. T~~two sets of substation voltage measurements for breaker-and-a-half and ring bus substation configurations and ~~. O~~one set of substation voltage measurements for each bus in other substation configurations;~~.~~

(b) For ~~all~~ transmission lines, each phase current and ~~the~~ neutral (residual) current; and

(c) For ~~all~~ transformers ~~that have~~with a low-side operating voltage of 100kV or above, each phase current and the neutral (residual) current. These phase currents can be from either the high-side or low-side of the transformer.

(2) Each Transmission Facility owner and Generation Resource owner shall have sequence of events recording data per the following requirements:

(a) Circuit breaker position (open/close) for each circuit breaker ~~that~~ it owns associated with the required monitored elements and connected directly to the transmission buses identified in paragraphs (1)(a) and (1)(b) of Section 6.1.2.2~~, Fault Recording and Sequence of Events Recording Equipment Location Requirements~~; and

(b) The following data ~~is required~~ as either part of the sequence of events recording data or fault recording digital status data:

(i) Circuit breaker position for each circuit breaker that it owns associated with monitored generator interconnects, transmission lines, and transformers;

(ii) Carrier transmitter control status (i.e. start, stop, keying) for associated transmission lines; and

(iii) Carrier signal receive status for associated transmission lines.

(3) Each Generation Resource owner and ESR owner shall have the following ~~point-on-wave~~ fault recording data~~, including calculations from the fault recording data if not directly measured,~~ for each triggered fault recording to determine:

(a) Time stamp;

(b) Phase-to-neutral voltage for each phase on low or high side of the Main Power Transformer (MPT);

(c) Each phase current and the residual or neutral current on low or high side of the MPT;

(d) If applicable, ~~A~~active and reactive power on low or high side of the MPT;

(e) If applicable, ~~F~~frequency and rate-of-change-of-frequency (df/dt) data for at least one generator-interconnected bus measurement;

(f) If applicable, dynamic reactive device input/output such as voltage, current, and frequency; and

(g) Applicable binary status.

(4) If the fault recorder does not directly measure the values in paragraphs (3)(d) through (3)(f) above, then dynamic disturbance recording or phasor measurement unit data is acceptable so long as data of sufficient resolution is available to validate dynamic models, identify protection system actions, and identify the cause of a ride-through failure.

(54) For each requested ~~Load~~ Facility identified by ERCOT in paragraphs (1)(d) and (1)(e) in Section 6.1.2.2~~, Fault Recording and Sequence of Events Recording Equipment Location Requirements~~, the interconnecting TSP or DSP shall have the following fault recording and sequence of events recording data for the identified Load elements to determine:

(a) Phase-to-neutral voltage for each phase of the transmission bus serving the Load, or other ERCOT approved voltages;

(b) Each phase current and neutral current for each Load terminal, or other ERCOT approved currents; and

(c) Circuit breaker status for those transmission circuit breakers directly associated with the Load terminals.

6.1.2.4 Fault Recording and Sequence of Events Recording Data Retention and Reporting Requirements

(1) Each Transmission Facility owner and Generation Resource owner shall ~~provide~~, upon request, provide to ERCOT~~the requesting Entity~~ fault recording and sequence of events recording data for the ~~transmission buses or~~ Transmission Elements identified in these requirements ~~to the requesting Entity in accordance with the~~ as follows~~ing~~:

(a) Data ~~will~~ shall be maintained and retrievable for ~~the maximum period of time the equipment reasonably allows and shall be retrievable for,~~ at a minimum:~~ten calendar days, inclusive of the day the data was recorded;~~

(i) ~~Thirty~~ Twenty calendar days, including the day the data was recorded, for fault recording and sequence of events recording equipment installed on or replaced after ~~January~~ June 1, 2024;

(ii) Ten calendar days, including the day the data was recorded, for fault recording and sequence of events recording equipment installed prior to ~~January~~June 1, 2024;

(b) Data subject to ~~item~~ paragraph (1)(a) above will be provided within ~~30~~ seven calendar days of request unless the requestor grants an extension ~~is granted by the requestor~~;

(c) Sequence of events recording data will be provided in ASCII Comma Separated Value (CSV) format as follows: Date, Time, Local Time Code, Substation, Device, State;

(d) Fault recording data that is not calculated will be provided in electronic files ~~that are~~ formatted in conformance with Institute of Electrical and Electronic Engineers (IEEE) C37.111, IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later; ~~and~~

(e) Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later~~.~~; and

(f) If available, fault recording data may~~shall~~ be provided in electronic files in SEL ASCII event report (.EVE), compressed ASCII (.CEV), or Motor Start Report (.MSR) in both raw and filtered format in addition to the data required above. ~~and Sequential Events Recorder record (.SER) format.~~

(2) The Transmission Facility owner and Generation Resource owner providing the requested fault recording and sequence of events recording data to ERCOT, the NERC Regional Entity, or NERC shall store the ~~requested~~ data for at least ~~a~~ three years ~~period~~ from the date the data was created.

6.1.3 ~~Phasor Measurement Recording Equipment Including~~ Dynamic Disturbance Recording Equipment Including Phasor Measurement Unit Equipment

(1) ~~Phasor measurement recording equipment includes all dynamic disturbance recording equipment with phasor measurement recording capability that meet the requirements in Sections 6.1.3.1, Recording and Triggering Requirements, and 6.1.3.3, Data Recording and Redundancy Requirements.~~ ~~By December 31, 20265, all dynamic disturbance recording equipment shall function as a phasor measurement unit and meet requirements in Section 6.1.3.1.2, Location Requirements, or a Facility Owner shall install a separate phasor measurement unit in addition to the dynamic disturbance recording equipment, and the phasor measurement unit shall have identical monitoring capabilities as the dynamic disturbance recording equipment.~~ Phasor measurement recording equipment includes all dynamic disturbance recording equipment with phasor measurement recording capability that meets the requirements in Section 6.1.3.1, Recording and Triggering Requirements, and 6.1.3.3, Data Recording and Redundancy Requirements. All new or replaced dynamic disturbance recording equipment

installed after June 1, 2024 shall function as or provide phasor measurement unit(s) and meet requirements in Section 6.1.3.1.2, Location Requirements. If an existing trigger based dynamic disturbance recording equipment fails to record and provide data more than one time in a rolling 36 month period, ERCOT may require it to be replaced with a phasor measurement recording capability that meets the requirements in Section 6.1.3.1, Recording and Triggering Requirements, and 6.1.3.3, Data Recording and Redundancy Requirements. In such instances, ERCOT would notify the facility owner and the facility owner shall install the new equipment within 18 months.

(2) ~~Phasor measurement~~ Dynamic disturbance recording equipment ~~required by these Operating Guides~~ shall be time synchronized with a Global Positioning System-based clock, or ERCOT-approved alternative, with sub-cycle (+/-~~<~~1 microsecond) timing accuracy and performance.

6.1.3.1 Dynamic Disturbance Recording Equipment Requirements

6.1.3.1.1 Recording and Triggering Requirements

(1) Dynamic disturbance recording equipment shall:~~Recorded electrical quantities shall be:~~

(a) ~~Provided in IEEE C37.118.1-2011, IEEE Standard for Synchrophasor format;~~ Have either continuous data recording or triggering for at least the following:

~~(i) Neutral (residual) overcurrent of 0.2 p.u. or less of rated current transformer secondary current,~~

(i~~ii~~) Any ~~P~~phase under-voltage below 0.85~~0.9~~ p.u. for two cycles or longer;

(ii) Phase under-voltage that would trigger Under-Voltage Load Shed (UVLS);

(iii~~iii~~) Any ~~P~~phase over-voltage greater than 1.15~~1.1~~ p.u. for two cycles or longer;

~~(iv) Phase overcurrent of 1.5 p.u. or less of rated current transformer secondary current or protective relay tripping for all protection groups;~~

(iv~~iiiv~~) Frequency below 59.5~~3~~ Hz or above 60.5~~6~~ Hz; and

(v~~ivvi~~) Frequency rate of change for low frequency of -0.08125 Hz/sec or high frequency of 0.125 Hz/sec;

(vi) ~~Document additional triggers and deviations from these trigger settings when local conditions dictate, with the review and approval of Any other trigger criterion (including deviations to the above triggers) based on local conditions as~~ ERCOT must review and approve any requested ~~D~~deviations from~~to~~ the above-referenced ~~triggering minimum~~ requirements ~~must be reviewed and approved by ERCOT~~.

(vii) Additional triggering in excess of ~~beyond~~ the minimums set forth in paragraph (a) above are ~~allowed~~permitted and do not require ERCOT's review and approval ~~by ERCOT~~.

(b) ~~Triggered r~~Record lengths of at least three minutes;

(c) A minimum output recording rate of 30 ~~times~~ samples per second; and

(d~~e~~) A minimum input sampling rate of 960 samples per second.~~; and~~

~~(d) Transmitted to an ERCOT phasor data concentrator via a communication link or stored locally per retention requirements in Section 6.1.3.4, Data Retention and Data Reporting Requirements.~~

6.1.3.1.2 Dynamic Disturbance Recording Equipment Location Requirements

(1) ERCOT shall identify and provide notification to~~Transmission Elements operated at or above 100 kV for which dynamic disturbance recording data is required, including~~~~and~~ Facility owners who shall install and maintain dynamic disturbance recording equipment at the following locations:

(a) ~~Non-IBR based~~ A Generation Resource(s) that is not an IBR with:

(i) Gross individual nameplate rating ~~at the Point of Interconnection (POI)~~ greater than or equal to 500 MVA; or

(ii) Gross individual nameplate rating ~~at the POI~~ greater than or equal to 300 MVA ~~where~~ if the gross plant/facility aggregate nameplate rating ~~at the POI~~ is greater than or equal to 1,000 MVA;

(b) Any ~~one~~ Transmission Element ~~that is~~ part of a stability-related (angular or voltage) ~~related~~ system operating limit;

(c) Each terminal of a high-voltage, direct current (HVDC) circuit with a nameplate rating greater than or equal to 300 MVA~~ at the POI~~, on the alternating current ~~portion~~ side of ~~the~~ a converter;

(d) One or more Transmission Elements ~~that are~~ part of an Interconnection Reliability Operating Limit (IROL); and

(e) Any one Transmission Element within a major voltage sensitive area as defined by an area with an in-service ~~Under-Voltage Load Shedding (~~UVLS~~)~~ program.

(2) ERCOT shall identify, and ~~provide notification to~~notify Facility owners of, a minimum dynamic disturbance recording coverage, ~~inclusive~~ including ~~of those~~ Transmission Elements identified above, of a least:

(a) One Transmission Element; and

(b) One Transmission Element per 3,000 MW of ERCOT's historical simultaneous peak Demand.

~~(3) Facility owners identified under paragraphs (1) or (2) above shall install dynamic disturbance recording equipment such that half of the identified facilities have the associated equipment installed by July 1, 2020, and all of the identified facilities by July 1, 2022.~~

~~(4) The facility owner(s), whether a Transmission Facility owner or Generation Resource owner, shall install phasor measurement recording equipment at the following facilities:~~

~~(a) Flexible AC transmission system devices configured to actively control steady-state voltage or power transfer capability, operated at or above 100 kV, and energized after July 1, 2015;~~

~~(b) Within 18 months after receiving written notice from ERCOT, a Transmission Facility identified by ERCOT associated with each published generic transmission constraint as deemed necessary by ERCOT;~~

~~(c) New generating facilities over 20 MVA aggregated at a single site placed into service after January 1, 2017; and~~

~~(d) Existing generating facilities over 20 MVA aggregated at a single site following any modification described in paragraph (1)(c) of Planning Guide Section 5.2.1, Applicability, with the modification's Initial Synchronization after January 1, 2022.~~

~~***[NOGRR177: Insert item (e) below upon system implementation of NPRR857:]***~~

~~(e) New Direct Current Ties (DC Ties) placed into service after January 1, 2019.~~

6.1.3.1.3 Dynamic Disturbance Recording Data Recording and Redundancy Requirements

(1) Recorded electrical quantities shall ~~be sufficient to~~ determine the following:

(a) For Transmission Facilit~~y owner locations~~ies meeting the requirements in Section 6.1.3.1.2, Location Requirements:

(i) Phase-to-neutral voltage magnitude/angle data for each phase from at least two distinct transmission level element measurement~~s~~ points;

(ii) Single phase current magnitude/angle data for each phase from at least two distinct transmission ~~level~~ lines; and

(iii) Frequency and rate-of-change-of-frequency (df/dt) data for at least two ~~t~~Transmission ~~level e~~Element measurement~~s~~ points.

(b) For Generati~~or~~on Resource owner locations ~~the~~ meeting the requirements in Section 6.1.3.1.2:

(i) Phase-to-neutral voltage, or phase-to-phase voltage magnitude/angle data for each phase from at least one generator-interconnected bus measurement point;

(ii) Single phase current magnitude/angle data for each phase from each interconnected generator ~~over 20 MVA or~~ on the high or low side of an MPT ~~main power transformer that represents the flow from multiple Intermittent Renewable Resources (IRRs) behind the main power transformer with total aggregated capacity greater than 20 MVA~~; ~~and~~

[NOGRR227: Replace item (ii) above with the following upon system implementation of NPRR973:]

(ii) Single phase current magnitude/angle data for each phase from each interconnected generator ~~over 20 MVA or~~ on the high or low side of a Main Power Transformer (MPT) ~~that represents the flow from multiple Intermittent Renewable Resources (IRRs) behind the MPT with total aggregated capacity greater than 20 MVA~~; ~~and~~

(iii) Active and reactive power on low or high side of the MPT;

(iv~~iii~~) Frequency and df/dt data for at least one generator-interconnected bus measurement~~.~~; and

(v) If applicable, dynamic reactive device input/output such as voltage, current, and frequency.

6.1.3.1.4 Dynamic Disturbance Recording Data Retention and Data Reporting Requirements

(1) A Market Participant required to have and maintain data regarding~~The minimum recorded~~ electrical quantities shall ~~be retained~~ maintain and retain that data ~~for the maximum period the equipment reasonably allows and~~, at a minimum~~, for~~per ~~the following guidelines~~:

(a) A ~~R~~rolling ten calendar day ~~window~~ period for all data ~~stored locally and not transmitted to an ERCOT phasor data concentrator~~;

(b) At least~~Minimum~~ three years ~~data retention by the Generation Resource owner~~ for event data ~~utilized~~ used for model validation in accordance with NERC Reliability Standards; and

(c) At least ~~Minimum~~ three years ~~data retention by the Generation Resource owner or Transmission Facility owner~~ for event data provided to ERCOT, the NERC Regional Entity, or NERC via written request ~~that is~~ recorded in the context of an ~~ERCOT-, NERC Regional Entity-, or NERC-initiated disturbance~~ event analysis or ~~event~~ review.

(2) Each ~~Transmission Facility owner and Generation Resource owner~~affected Market Participant shall provide to ERCOT~~the requesting Entity~~, upon request, dynamic disturbance recording data ~~for the buses or Transmission Elements identified in these requirements to the requesting entity, in accordance with the following~~ as follows:

(a) Data ~~will~~ must be retrievable for ~~the period of~~ ten calendar days, inclu~~sive of~~ding the day the data was recorded;

(b) Data subject to ~~item~~ paragraph (2)(a) above ~~will be provided~~ within ~~30~~ seven calendar days of a request unless the requestor grants an extension ~~is granted by the requestor~~;

(c) Dynamic disturbance recording data ~~will be provided~~ in electronic files ~~that are~~ formatted in conformance with IEEE C37.111, revision C37.111-1999 or later;

(d) Data files ~~will be~~ named in conformance with IEEE C37.232, revision C37.232-2011 or later.

6.1.3.2 Phasor Measurement Unit Requirements

(1) Phasor measurement unit equipment includes all dynamic disturbance recording equipment with phasor measurement recording capability meeting the requirements in Sections 6.1.3.2.1, Phasor Measurement Unit Recording Requirements, and 6.1.3.2.3, Phasor Measurement Unit Data Recording and Redundancy Requirements.

(2) Phasor measurement unit equipment shall be time synchronized with a Global Positioning System-based clock, or ERCOT-approved alternative, with sub-cycle (+/-~~<1~~2 ~~microsecond~~millisecond) timing accuracy and performance.

6.1.3.2.1 Phasor Measurement Unit Recording Requirements

(1) Recorded electrical quantities shall have continuous recording and shall:

(a) Comply~~Be compliant~~ with ~~provided in~~ IEEE C37.118.1-2011 or later, IEEE Standard for Synchrophasor format;

(b) Have a minimum output recording rate of 30 samples per second;

(c) Have a minimum input sampling rate of 960 samples per second; and

(d) ~~Be transmitted to an ERCOT phasor data concentrator via a communication link or stored~~ Be ~~S~~stored locally in accordance with the requirements in Section 6.1.3.2.4, Phasor Measurement Unit Data Retention and Data Reporting Requirements.

6.1.3.2.2 Phasor Measurement Unit Location Requirements

(1) Each Transmission Facility owner(s) or Generation Facility owner(s) shall, as applicable, install phasor measurement unit equipment at the following locations:

(a) Flexible AC transmission system devices configured to actively control steady-state voltage or power transfer capability operated at or above 100 kV and energized after July 1, 2015;

(b) A Transmission Facility deemed necessary for each published generic transmission constraint within ~~18 months~~~~three~~two ~~calendar~~ years of receiving written notice from ERCOT;

(c) New Generation Resources or ESRs over 20 MVA aggregated at a single site and~~,~~ connected to a Transmission Facility at or above 60 kV~~,~~ and ~~aggregated at a single site~~ placed into service after January 1, 2017;

(d) Existing Generation Resources or ESRs over 20 MVA aggregated at a single site and~~,~~ connected to a Transmission Facility at or above 60 kV~~,~~ ~~aggregated at a single site~~ following any modification described in paragraph (1)(c) of Planning Guide Section 5.2.1, Applicability, with the modification's Initial Synchronization after January 1, 2022;

[NOGRR177: Insert item (e) below upon system implementation of NPRR857 and renumber accordingly:]

(e) New Direct Current Ties (DC Ties) placed into service after January 1, 2019;

~~(e) For aAny Generation Resource or ESR that has experiencesd a frequency ride-through or voltage ride-through failure, if required by ERCOT. ERCOT may require installation of a phasor measurement unit andthat transmitsssion of the data to an ERCOT phasor data concentrator via a communication link. The Generation Resource or ESR owner shall install the phasor measurement unit at a location specified by ERCOT as soon as practicable but no longer than 18 monthsthreetwo calendar years after ERCOT notifies the Entity it must install the equipment., The equipment and shall begin transmitting the data to the ERCOT phasor data concentrator within 60 days afterof installationing required recording equipmentis completed.~~

(e) For any Generation Resource or ESR that has not installed phasor measurement units and experiences an unexpected trip or significant reduction in output in response to a system disturbance for which it is unable to determine the cause, ERCOT may require installation of a phasor measurement unit consistent with the requirements of Section 6.1.3, Dynamic Disturbance Recording Equipment Including Phasor Measurement Unit Equipment. The Generation Resource or ESR owner shall install the phasor measurement unit at a location specified by ERCOT as soon as practicable but no longer than two years after the date that ERCOT notifies the Entity it must install the equipment.

(f~~e~~f) Each Transmission Element considered part of a monitored IROL interface~~,~~ within ~~three~~two ~~calendar~~ years of notification ~~from~~by ERCOT;

(g~~f~~g) ~~For any s~~Synchronous condensers ~~used to~~ supporting the transmission system installed after ~~January~~June 1, 2024.

(h~~g~~h) ~~Within three calendar years of notification from ERCOT, aAny one~~A Transmission Element within:

(i) A voltage sensitive area consisting of ~~as defined by~~ an area with an ~~in-service~~active UVLS program;

(ii) An area of the ERCOT System with 3,000 MW of ERCOT's historical simultaneous peak Demand; and

(iii) An area with greater than 1,000 MW of Generation Resources and ESRs with a ~~identified~~ stability risk~~s~~ identified by ERCOT.

(iv) An area identified in items (i) through (iii) above shall have its equipment installed within two years of the date on which ERCOT informs the owner of the need to install the equipment.

(~~f~~ih) ~~For any~~~~An individual Load consisting of one or more Facilities at a single site with an aggregate peak demand~~ ~~ERCOT may require installation of a phasor measurement unit for Loads~~ For locations that have experienced an abnormal trip or immediate Load change greater than or equal to 20 MW~~MVA~~ ~~that experienced abnormal trips or Load reductions after a fault~~ (including if caused by a DGR, DESR, or SODG ~~distribution connected Resources~~) after a fault:~~.~~ ~~ERCOT may require transmitting the data to an ERCOT phasor data concentrator via a communication link for more than one failure. The Transmission Facility owner or DSP shall install the phasor measurement unit at a location specified by ERCOT as soon as practicable but no longer than 18 months after ERCOT notifies the Transmission Facility owner or DSP it must install the recording equipment, and transmit the data within 60 days of installing the required recording equipment;~~

(i) ERCOT may require ~~the~~ installation of phasor measurement recording equipment;

(ii) The interconnecting Transmission Service Provider (TSP) or Distribution Service Provider (DSP) shall ~~install~~ensure the recording equipment is installed;

(iii) A suitable location for the recording equipment will be coordinated between ERCOT and the interconnecting TSP or DSP;

(iv) The recording equipment will be installed as soon as practicable, but no longer than ~~18 months~~~~three~~two ~~calendar~~ years after ERCOT notifies the TSP or DSP ~~it must~~of the need to install the equipment, unless the requestor provides an extension;

(v) If the TSP or DSP determines ~~that~~ it cannot install the recording equipment ~~installation is infeasible~~ due to engineering, technical or operational ~~reasons~~constraints, it will provide to ERCOT, in writing, supporting data or documents~~such rationale in writing to ERCOT~~.

~~(g) The Transmission Facility owner or DSP shall install the phasor measurement unit for each individual Load with more than 20 MVA of~~

~~distribution connected Resources by December 31, 2024 or within 120 days of reaching the 20 MVA threshold; and~~

~~(h) The Transmission Facility owner shall install the phasor measurement unit for each new individual Load greater than 75 MVA aggregated at a single site placed into service after January 1, 2023.~~

(~~g~~~~i~~j~~i~~) ~~For any~~Any ~~individual~~ Load consisting of one or more Facilities at a single site with an aggregate peak Demand greater than or equal to 75 MW behind one or more ~~common Points of Interconnection (POIs) or~~ Service Delivery Points if ERCOT requires phasor measurement recording equipment. If required:

~~(i) ERCOT may require the installation of phasor measurement recording equipment;~~

(~~i~~i) The interconnecting ~~Transmission Service Provider (~~TSP~~)~~ or ~~Distribution Service Provider (~~DSP~~)~~ shall ~~install~~ensure the recording equipment is installed;

(~~i~~ii) A suitable location for the recording equipment will be coordinated between ERCOT and the interconnecting TSP or DSP;

(iii~~v~~) The recording equipment will be installed as soon as practicable, but no longer than ~~18 months~~~~three~~two ~~calendar~~ years after ERCOT notifies the TSP or DSP ~~it must~~of the need to install the equipment, unless ~~the requestor provides~~ERCOT grants an extension;

(iv) If the TSP or DSP determines it cannot install~~that~~ the recording equipment ~~installation is infeasible~~ due to engineering, technical or operational ~~reasons~~constraints, it will provide to ERCOT, in writing, supporting data or documents~~such rationale in writing to ERCOT for consideration~~.

(2) ~~By December 31, 2024,~~ Transmission Facility owners and Generation Resource Facility owners shall install ~~at least 50% of the~~ applicable new phasor measurement units identified in paragraph (1) above as soon as practicable.~~and 100% of the new phasor measurement units by December 31, 2025.~~

[NOGRR255: Replace paragraph (2) above with the following no earlier than <Insert Date at least ~~18 months~~~~three~~two ~~calendar~~ years after PUCT approval>:]

(2) Transmission Facility owners and Generation Resource Facility owners shall have at least 50% of ~~the~~ applicable new phasor measurement units identified in paragraph (1) above installed.

[NOGRR255: Delete paragraph (2) no earlier than <Insert Date at least ~~36 months~~~~five~~four ~~calendar~~ years after PUCT approval>.]

~~(3) ERCOT shall identify Transmission Elements for which data must be transmitted to an ERCOT phasor data concentrator via a communication link, including the following:~~

~~(a) Each Transmission Element part of a monitored IROL interface;~~

~~(b) Each static Volt-Ampere reactive (VAr) compensator, static synchronous compensator (STATCOM), or synchronous condenser with a lagging or leading MVAr capability of 100 MVAr or greater;~~

~~(c) Any one Transmission Element within:~~

~~(i) A voltage sensitive area as defined by an area with an in-service Under-Voltage Load Shedding (UVLS) program;~~

~~(ii) An area of the ERCOT System with 3,000 MW of ERCOT's historical simultaneous peak Demand; and~~

~~(iii) An area with greater than 1,000 MW of Generation Resources and ESRs with identified stability risks.~~

~~(4) Each Transmission Facility owner shall install phasor measurement recording equipment for a Transmission Element identified in paragraph (2) above within 18 months after receiving written notice from ERCOT. Each Transmission Facility owner shall transmit the phasor measurement recording equipment data to an ERCOT phasor data concentrator via a communication link for each Transmission Element identified in paragraph (2) above within 120 calendar days after receiving written notice if the phasor measurement reporting equipment is already installed or within 120 calendar days of the date the phasor measurement equipment is installed, whichever is sooner.~~

6.1.3.2.3 ~~–~~Phasor Measurement Unit Data Recording and Redundancy Requirements

(1) Recorded electrical quantities shall include data to determine the following:

(a) For Transmission Facility owner locations meeting the requirements in Section 6.1.3.2.2, Phasor Measurement Unit Location Requirements:

(i) Time stamp;

(ii) Phase-to-neutral voltage magnitude/angle data for each phase from at least two distinct Transmission Element measurement points;

(iii) Single phase current magnitude/angle data for each phase from at least two distinct Transmission lines; and

(iv) Frequency and rate-of-change-of-frequency (df/dt) data for at least two Transmission Element measurement points.

(b) For Generat~~o~~ion~~r~~ Resource or ESR ~~owner~~ locations meeting the requirements in Section 6.1.3.2.2:

(i) Time stamp;

(ii) Phase-to-neutral voltage for each phase on the low or high side of the MPT;

(iii) Each phase current and the residual or neutral current~~, including calculated values if not directly measured,~~ on the low or high side of the MPT;

(iv) Active and reactive power on the low or high side of the MPT;

(v) Frequency and df/dt data for at least one generator-interconnected bus measurement; and

(vi) If applicable, dynamic reactive device input/output such as voltage, current, and frequency.

(c) For ~~Load~~ Facilities identified by ERCOT in Section 6.1.3.2.2~~, Phasor Measurement Unit Location Requirements~~:

(i) Phase-to-neutral voltage, or phase-to-phase voltage magnitude/angle data for each phase from at least one transmission terminal bus measurement point, or other ERCOT approved voltages; and

(ii) Single phase current magnitude/angle data for each phase from each interconnected Load terminal on the high or low side of Load delivery point, or other ERCOT approved currents.

6.1.3.2.4 Phasor Measurement Unit Data Retention and Data Reporting Requirements

(1) ~~A~~ Market Participants ~~required to have and~~ must maintain data regarding the minimum recorded electrical quantities for ~~shall maintain and retain that data for~~

~~the maximum period of time~~ ~~the equipment reasonably allows and~~ ~~at a minimum~~ ~~for~~ at least:

(a) A rolling 20~~30~~ calendar day period for all data stored locally;

(b) At least three years for event data used for model validation in accordance with NERC Reliability Standards; and

(c) At least three years for event data provided to ERCOT, the NERC Regional Entity, or NERC via written request recorded in the context of an ~~ERCOT, NERC Regional Entity, or NERC-initiated~~ event analysis or review.

(2) Each affected Market Participant shall provide ~~to the requesting Entity~~ERCOT, upon request, phasor measurement unit data for the ~~buses or Transmission~~ Elements identified in these requirements as follows:

(a) Data must be retrievable for ~~30~~20 calendar days, including the day the data was recorded;

(b) Data subject to ~~item~~ paragraph (2)(a) above within seven calendar days of a request unless the requestor grants an extension;

(c) Data in electronic files formatted in conformance with IEEE C37.111, revision C37.111-1999 or later;

(d) Data files named in conformance with IEEE C37.232, revision C37.232-2011 or later.

6.1.4 Fault Recording, Sequence of Events Recording, and Phasor Measurement Unit Requirements for Inverter-Based Resources (IBRs)

(1) ~~Inverter-Based Resources (~~IBRs~~)~~ include any source of electric power connected to the ERCOT System via a power electronic interface that consists of one or more IBR unit(s) capable of exporting active power from a primary energy source or energy storage system. ~~An IBR unit is an individual inverter device or group of multiple inverters connected together at a single point of connection. An IBR unit may be an inverter, converter, wind turbine generator, or HVDC converter.~~

(2) All transmission-~~-~~connected IBR facilities operating at 60 kV ~~and above~~ with gross aggregated nameplate capacity of 20 MVA ~~or above~~ at a single site ~~are subject to~~must meet all requirements in this section.

(3) ~~By December 31, 2024,~~ Facility owners shall install ~~at least 50% of the~~ new fault recording and sequence of events recording equipment identified in this section~~,~~ ~~and 100% of the new fault recording and sequence of events recording equipment by December 31, 2025~~ as soon as practicable.

[NOGRR255: Replace paragraph (3) above with the following no earlier than <Insert Date at least ~~18 months~~~~three~~two ~~calendar~~ years after PUCT approval>:]

(3~~2~~) Facility owners shall have at least 50% of ~~the~~ new fault recording equipment, sequence of events recording equipment, and phasor measurement units identified in paragraph (2~~1~~) above installed.

[NOGRR255: Delete paragraph (3) no earlier than <Insert Date at least ~~36 months~~~~five~~four ~~calendar~~ years after PUCT approval>.]

6.1.4.1 Fault Recording and Sequence of Events Recording Equipment Requirements

(1) Required fault recording equipment shall be time synchronized with a Global Positioning System-based clock, or ERCOT approved alternative, with ~~sub-cycle (<+/-1 microsecond) timing~~ synchronized device clock accuracy and performance withi~~n~~g +/- 100 microseconds of Coordinated Universal Time (UTC), with or without a local time offset for Central Prevailing Time (CPT).

(2) Required sequence of events recording equipment shall be time synchronized with a Global Positioning System-based clock, or ERCOT-approved alternative, with +/- 100 microseconds of Coordinated Universal Time (UTC), with or without a local time offset for Central Prevailing Time (CPT).

6.1.4.1.1 Sequence of Events Recording Data Requirements

(1) Generation Resource owners and ESR owners shall have sequence of events data for all positions (open/close) for circuit breakers associated with the MPT(s), collector bus, and shunt static or dynamic reactive device(s).~~:~~

~~(a) All circuit breaker positions;~~

~~(b) For at least one IBR unit connected to the last 10% of each collector feeder length. IBR units installed prior to the effective date of this standard and are not capable of recording some of this data are excluded from providing that specific data:~~

~~(i) All fault codes;~~

~~(ii) All Fault alarms;~~

~~(iii) Change of operating mode;~~

~~(iv) High and low voltage ride-through mode status;~~

~~(v) High and low voltage frequency ride-through mode status; and~~

~~(vi) Control system command values, reference values, and feedback signals.~~

6.1.4.1.2 Fault Recording Data and Triggering Requirements

(1) Generation Resource owners and ESR owners shall have fault recording data to determine ~~or calculate, if not directly measured,~~ the following electrical quantities for each triggered fault recording record:

(a) Generation Resource or ESR level fault recording data:

(i) Time stamp;

(ii) Phase-to-neutral voltage for each phase on the ~~low or~~ high side of the MPT;

(iii) Each phase current and the residual or neutral current on the ~~low or~~ high side of the MPT;

(iv) If applicable, ~~A~~active and reactive power on the ~~low or~~ high side of the MPT;

(v) If applicable, ~~F~~frequency and rate-of-change-of-frequency (df/dt) data for at least one generator-interconnected bus measurement; and

(vi) If applicable, dynamic reactive device input/output such as voltage, current, and frequency.

(vii) Applicable binary status.

~~(b) Individual IBR unit fault recording data from at least one IBR unit connected to any feeder as a location within the last 10% of eachthe longest collector feeder length:~~

~~(i) Each AC phase-to-neutral or phase-to-phase voltage, as applicable, at IBR unit terminals or on high side of the IBR unit transformer;~~

~~(ii) Each AC phase current and the residual or neutral current, as applicable, on IBR unit terminals or on high side of the IBR unit transformer; and~~

~~(iii) DC bus current and voltage. IBR units installed prior to the effective date of this standard and are not capable of recording this data are excluded.~~

(2) If the fault recorder does not directly measure the values in paragraphs (1)(a)(iv) through (1)(a)(vi) above, then phasor measurement unit data is acceptable so long as data of sufficient resolution is available to validate dynamic models, identify protection system actions, and identify the cause of a ride-through failure.

(3~~2~~) Fault recording equipment shall meet the following requirements for ~~both~~a Generation Resource or ESR ~~level and individual IBR unit level~~ as described in paragraph (1) above:

(a) Have either continuous data recording or ~~T~~triggering for at least the following:

~~(i) Neutral (residual) overcurrent of 0.2 p.u. or less of rated current transformer secondary current;~~

~~(ii) Phase under-voltage below 0.9 p.u. for two cycles or longer;~~

~~(iii) Phase over-voltage greater than 1.1 p.u. for two cycles or longer;~~

~~(iv). Phase overcurrent of 1.5 p.u. or less of rated current transformer secondary current or protective relay tripping for all protection groups;~~

~~(v) Frequency below 59.53 Hz or above 60.56 Hz; and~~

~~(vi) Frequency rate of change for low frequency of -0.08125 Hz/sec or high frequency of 0.125 Hz/sec;~~

(i) High-side of the MPT fault recording triggers and, if applicable, any dynamic reactive device FR triggers:

(A) Neutral (residual) overcurrent of 0.20 per unit (p.u.) or~~f~~ less of rated current transformer secondary current;

(B) Any phase under-voltage between 0.85 p.u. and 0.90 p.u., or

(1) Any phase overcurrent above 1.05 p.u. of the maximum emergency current rating, or

(2) Protective relay tripping for all protection groups;

(C) Any phase over-voltage greater that 1.10 p.u.;

(D) Frequency below 59.5 Hz or above 60.5 Hz;

(E) Frequency rate of change for low frequency of -0.08125 Hz/sec or high frequency of 0.125 Hz/sec;

~~(ii) IBR unit level fault recording triggers:~~

~~(A) Any phase under-voltage between 0.85 p.u. and 0.90 p.u.;~~

~~(B) Any phase over-voltage greater than 1.10 p.u.;~~

~~(C) Frequency below 59.5 Hz or above 60.5 Hz;~~

~~(D) Frequency rate of change for low frequency of -0.08125 Hz/sec or high frequency of 0.125 Hz/sec;~~

(b) Minimum recording rate of:

(i) ~~128~~64 samples per cycle for any Fault recording equipment installed on or replaced after ~~January~~June 1, 2024;

(ii) 16 samples per cycle for any Fault recording equipment installed prior to ~~January~~June 1, 2024~~ but set as close to 128 samples per cycle as the equipment allows~~; and

(c) A single record or multiple records that include pre-trigger record length of at least two cycles and a total record length of at least ~~5~~2 seconds for the same trigger point.

6.1.4.3 Phasor Measurement Unit Equipment Requirements

(1) Phasor measurement unit equipment shall be time synchronized with a Global Positioning System-based clock, or ERCOT-approved alternative, with ~~sub-cycle (+/-<1 microsecond) timing~~ synchronized device clock accuracy and performance within +/- 100 microseconds of Coordinated Universal Time (UTC), with or without a local time offset for Central Prevailing Time (CPT).

(2) Recorded electrical quantities shall have continuous recording and be:

(a) Provided in IEEE C37.118.1-2011 or later, IEEE Standard for Synchrophasor format.~~;~~ However, Generation Resources in commercial operation before January 1, 2017 may provide the data in IEEE C37.118.1-2005 format when technically infeasible for its installed equipment to meet the IEEE C37.118.1-2011 or later format;

(b) A minimum output recording rate of 60 samples per second;

(c) A minimum input sampling rate of 960 samples per second; and

(d) Transmitted to an ERCOT phasor data concentrator via a communication link or stored locally per retention requirements in Section 6.1.4.4, Data Retention and Data Reporting Requirements for Fault Recording, Sequence of Events Recording, and Phasor Measurement Unit Equipment.

(3) ~~Recorded electrical quantities shall include the following~~Facility owners shall have phasor monitoring data to determine the following ~~electrical quantities~~:

(a) Time stamp;

(b) Phase-to-neutral voltage, or phase-to-phase voltage magnitude/angle data for each phase from at least one generator-interconnected bus ~~measurement~~;

(c) Single phase current magnitude/angle data for each phase on the high or low side of an MPT that represents the flow from one or multiple IBR unit(s) behind the MPT;

(d) Frequency and rate-of-change-of-frequency (df/dt) data for at least one generator-interconnected bus ~~measurement~~; and

(e) Calculated active and reactive power output on the high or low side of the MPT that represents the flow from one or multiple IBR unit(s) behind the MPT.

6.1.4.4 Data Retention and Data Reporting Requirements for Fault Recording, Sequence of Events Recording, and Phasor Measurement Unit Equipment

(1) A Generation Resource owner or ESR owner required to have ~~and maintain~~ data regarding electrical quantities shall maintain and retain the data, ~~for the maximum period the equipment allows and~~ at a minimum, for:

(a) A rolling ~~30~~20 calendar day period for all data;

(b) At least three years (from the date the data was recorded) for event data used for model validation in accordance with NERC Reliability Standards; and

(c) At least three years for event data provided to ERCOT, the NERC Regional Entity, or NERC via written request recorded in the context of an ~~ERCOT, NERC Regional Entity, or NERC-initiated~~ event analysis or review.

(2) Each Generation Resource owner and ESR owner shall provide ~~to the requesting Entity~~ERCOT, upon request, fault recording, sequence of events recording, and ~~P~~phasor measurement unit data ~~locations~~ as follows:

(a) Data for ~~30~~ 20 calendar days, including the day the data was recorded;

(b) Data subject to ~~item~~paragraph (2)(a) above within seven calendar days of a request unless ~~the requestor~~ERCOT grants an extension;

(c) Sequence of events data in ASCII Comma Separated Value (CSV) format as follows: Date, Time, Local Time Code, Substation, Device, State;

(d) Fault recording and phasor measurement unit data in electronic files formatted in conformance with Institute of Electrical and Electronic Engineers (IEEE) C37.111, IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later;

(e) Data files named in conformance with IEEE C37.232, revision C37.232-2011 or later; and

(f) If available, fault recording data in electronic files in SEL ASCII event report (.EVE), compressed ASCII (.CEV), Motor Start Report (.MSR) and Sequential Events Recorder record (.SER) format.

6.1.~~4~~5 Maintenance and Testing Requirements

~~(1) Each Transmission Facility owner and Generation Resource owner with dynamic disturbance recording, fault recording, and/or sequence of events recording equipment identified by these requirements shall maintain and test their recording equipment as follows:~~

~~(a) Calibration of the recording devices shall be performed at installation and when records from the equipment indicate a calibration problem.~~

(1) Each Market Participant with dynamic disturbance recording, phasor measurement recording, fault recording, or sequence of events recording equipment identified by Section 6.1.2, Fault Recording and Sequence of Events Recording Equipment, Section 6.1.3, Dynamic Disturbance Recording Equipment Including Phasor Measurement Unit Equipment, and Section 6.1.4, Fault Recording, Sequence of Events Recording, and Phasor Measurement Unit Requirements for Inverter-Based Resources (IBRs), shall maintain and test ~~recording~~its equipment as follows:

(a) Calibrate or configure the ~~recording~~ devices at installation and when records from the equipment indicate a calibration or configuration problem;

~~(b) Maintain phasor measurement recording equipment to ensure a minimum availability of good data quality of at least 95% on a rolling 30 day basis if transmitted to an ERCOT phasor data concentrator via a communication link;~~

(b~~c~~) ~~Maintain phasor measurement recording equipment t~~To ensure data stored locally is available upon request by verifying data availability and quality at least once every ~~30~~60 calendar days, or institute an automated notification system to detect when the equipment ceases recording required data or fails to timely refresh the data.

(2) Each Market Participant with dynamic disturbance recording equipment, phasor measurement recording, fault recording, or sequence of events recording equipment identified by Section 6.1.2, ~~Fault Recording and Sequence of Events Recording Equipment,~~ Section 6.1.3, ~~Dynamic Disturbance Recording Equipment Including Phasor Measurement Unit Equipment,~~ and Section 6.1.4 ~~, Fault Recording, Sequence of Events Recording, and Phasor Measurement Unit Requirements for Inverter-Based Resources (IBRs),~~ shall, within ~~30~~90 calendar days of ~~the discovery of~~discovering a failure of the required data production, either:

(a) Restore the recording capability, or

(b) Notify and submit to ERCOT a plan and timeline for restoring the equipment ~~to have~~ recording capabilities ~~restored~~.

6.1.6~~5~~ Equipment Reporting Requirements

(1) Each Market Participant with dynamic disturbance recording, phasor measurement recording, fault recording, or sequence of events recording equipment identified by Section 6.1.2, Fault Recording and Sequence of Events Recording Equipment, Section 6.1.3, Dynamic Disturbance Recording Equipment Including Phasor Measurement Unit Equipment, and Section 6.1.4, Fault Recording, Sequence of Events Recording, and Phasor Measurement Unit Requirements for Inverter-Based Resources (IBRs), shall:

(a) ~~Disturbance monitoring equipment owners shall~~ M~~m~~aintain a current database summarizing ~~their~~ disturbance monitoring equipment installations that~~.~~

~~(2) The database shall~~ includes installation location, type of equipment, equipment make and model~~ of equipment~~, operational status, and a list~~ing~~ of the major equipment ~~being~~ monitored;~~.~~ ~~A~~and

(b) ~~Additionally,~~ Have and maintain a complete list of all monitored points at each Facility ~~installation shall be maintained by disturbance monitoring equipment owners~~ and ~~provided~~, when requested ~~specifically~~ by ERCOT, the NERC Regional Entity, or NERC, provide the list within 30 days.

6.1.~~6~~7 Review Process

(1) After December 31, 2025, ERCOT shall review ~~dynamic disturbance recording~~disturbance monitoring equipment locations for adequacy when significant changes are made to the ERCOT System or at least every five calendar years.

(2) Transmission Facility owners shall review fault recording and sequence of events recording equipment locations for compliance at least every five calendar years.

(3) Existing Facility owners identified in the reviews shall have three ~~calendar~~ years from the time of review, or from the time of notification from others, to install the equipment.

ERCOT Nodal Operating Guides
Section 8
Attachment M

Selecting Buses for Capturing Sequence of Events Recording and Fault Recording Data

~~February 1, 2018~~TBD

This attachment provides the Transmission Facility owner the methodology to use for selecting bus locations for capturing sequence of events recording and fault recording data.

To identify monitored bulk electric system buses for sequence of events recording and fault recording data, each Transmission Facility owner shall follow sequentially, unless otherwise noted, the steps listed below:

Step 1. Determine a complete list of bulk electric system buses that it owns, excluding buses or Facilities solely representing Inverter-Based Resources (IBRs), as those locations are addressed outside of the process described in this attachment.

For the purposes of this attachment, a single bulk electric system bus includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus.

Step 2. Reduce the list to those bulk electric system buses that have a maximum available calculated three phase short circuit MVA of 1,500 MVA or greater. If there are no buses on the resulting list, proceed to Step 7.

Step 3. Determine the 11 bulk electric system buses on the list with the highest maximum available calculated three phase short circuit MVA level. If the list has 11 or fewer buses, proceed to Step 7.

Step 4. Calculate the median MVA level of the 11 bulk electric system buses determined in Step 3.

Step 5. Multiply the median MVA level determined in Step 4 by 20 percent.

Step 6. Reduce the bulk electric system buses on the list to only those that have a maximum available calculated three phase short circuit MVA higher than the greater of:

- 1,500 MVA or
- 20 percent of median MVA level determined in Step 5.

Step 7. If there are no bulk electric system buses on the list: the procedure is complete and no fault recording and sequence of events recording data will be required. Proceed to Step 9.

If the list has one or more but less than or equal to 11 bulk electric system buses: fault recording and sequence of events recording data is required at the bulk electric system bus with the highest maximum available calculated three phase short circuit MVA as determined in Step 3.

During re-evaluation efforts, if the three-phase short circuit MVA of the newly identified bulk electric system bus is within 15% of the three-phase short circuit MVA of the currently applicable BES bus with sequence of events recording and fault recording data than it is not necessary to change the applicable BES bus. Proceed to Step 9.

If the list has more than 11 bulk electric system buses: fault recording and sequence of events recording data is required on at least the 10 percent of the bulk electric system buses determined in Step 6 with the highest maximum available calculated three phase short circuit MVA. Proceed to Step 8.

Step 8. Fault recording and sequence of events recording data is required at additional bulk electric system buses on the list determined in Step 6. The aggregate of the number of bulk electric system buses determined in Step 7 and this Step will be at least 20 percent of the bulk electric system buses determined in Step 6. The additional bulk electric system buses are selected, at the Transmission Facility owner's discretion, to provide maximum wide-area coverage for fault recording and sequence of events recording data. The following bulk electric system bus locations are recommended:

- Electrically distant buses or electrically distant from other disturbance monitoring equipment devices.
- Voltage sensitive areas.
- Cohesive load and generation zones.
- Bulk electric system buses with a relatively high number of incident transmission circuits.
- Bulk electric system buses with reactive power devices.
- Major Facilities interconnecting outside the Transmission Owner's area.

Step 9. The list of monitored bulk electric system buses for fault recording and sequence of events recording data is the aggregate of the bulk electric system buses determined in Steps 7 and 8.

ERCOT Impact Analysis Report

NOGRR Number	255	**NOGRR Title**	**High Resolution Data Requirements**
Impact Analysis Date	June 29, 2023		
Estimated Cost/Budgetary Impact	None.		
Estimated Time Requirements	No project required. This Nodal Operating Guide Revision Request (NOGRR) can take effect following Public Utility Commission of Texas (PUCT) approval.		
ERCOT Staffing Impacts (across all areas)	Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	No impacts to ERCOT computer systems.		
ERCOT Business Function Impacts	ERCOT will update its business processes to implement this NOGRR.		
Grid Operations & Practices Impacts	No impacts to ERCOT grid operations and practices.		

Evaluation of Interim Solutions or Alternatives for a More Efficient Implementation
None offered.

Comments
None.

Board Report

NOGRR Number	258	NOGRR Title	Related to NPRR1198, Congestion Mitigation Using Topology Reconfigurations
Date of Decision		June 18, 2024	
Action		Recommended Approval	
Timeline		Normal	
Estimated Impacts		Cost/Budgetary: None Project Duration: No project required	
Proposed Effective Date		Upon implementation of Nodal Protocol Revision Request (NPRR) 1198, Congestion Mitigation Using Topology Reconfigurations	
Priority and Rank		Not applicable	
Nodal Operating Guide Sections Requiring Revision		11.1, Introduction 11.4, Remedial Action Plan 11.4.1, Remedial Action Plan Process 11.6, Pre-Contingency Action Plans 11.8, Extended Action Plans (new) 11.8.1, Extended Action Plan Process (new)	
Related Documents Requiring Revision/Related Revision Requests		NPRR1198, Congestion Mitigation Using Topology Reconfigurations Planning Guide Revision Request (PGRR) 113, Related to NPRR1198, Congestion Mitigation Using Topology Reconfigurations	
Revision Description		This Nodal Operating Guide Revision Request (NOGRR) proposes changes to align the Nodal Operation Guides with NPRR1198 that adds language to allow the use of Remedial Action Plans (RAPs) and Extended Action Plans (EAPs) to facilitate the market use of the ERCOT Transmission Grid. NOGRR258 also adds guardrails to ensure that topology reconfiguration requests meet basic reliability and economic criteria, and defines the process for submission, review, and approval of EAPs. This NOGRR and NPRR1198 leverage ERCOT's existing Constraint Management Plan (CMP) process to quickly mitigate critical transmission congestion impacts by establishing a scalable process for topology reconfiguration requests that is transparent, predictable, equitable, workable, reliable, and compatible with existing planning processes.	

	ERCOT already leverages topology optimization in the CMP processes. Since NPRR529, Congestion Management Plan was introduced in 2013 with the limitations that NPRR1198 proposes to revise, the power industry has evolved and there have been technological improvements that make transmission topology reconfigurations a powerful option to mitigate congestion beyond just use cases for which there is no feasible Security-Constrained Economic Dispatch (SCED) solution.
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	Transmission congestion in ERCOT has been increasing. The Real-Time congestion value for 2022 was $2.8B, which exceeded the $2.1B for the full year 2021, even accounting for impacts from Winter Storm Uri. Congestion has major impacts on grid reliability, electricity costs, and open access. All Market Participants are affected. The proposed revisions aim to make the best use possible of the ERCOT Transmission Grid to mitigate congestion and its impacts. Grid topology optimization finds network reconfiguration options to re-route power flows around bottlenecks. Solutions validated by the System Operator can be rapidly implemented using existing circuit breaker equipment. Several other regions (e.g., Midcontinent Independent System Operator (MISO), Southwest Power Pool (SPP)) currently endorse reconfiguration actions for congestion mitigation and impacts have been overwhelmingly positive. The use of optimal reconfigurations in those regions has demonstrated significant economic and reliability benefits such as 10% transfer

	capacity increase for major thermal constraints, 40% reduction in congestion costs, 70% reduction in the frequency of constraint overloads, and mitigation of transmission bottlenecks; thus, increasing generation deliverability, improving resource adequacy, and providing resilience benefits. In the context of CMPs, topology reconfigurations are effective, inexpensive, and low-risk. Prior to wholesale competition, Texas utilities made extensive use of topology reconfigurations to mitigate congestion for generation deliverability. The original mathematical formulation for SCED includes transmission topology as an input for price formation. Reconfigurations are a latent feature of the market design; thus, their application is not at all “out-of-market". When SCED was first implemented, there was no known method to identify optimal network topologies in operational time scales. Computational advances have now reduced the time required for solution identification to just a few seconds. The EAPs outlined in this NOGRR and NPRR1198 can be proposed by ERCOT or any Market Participant to implement a switching solution for a set period of time. The solution is approved by ERCOT, impacted generators, and Transmission Operators (TOs). A detailed list of guardrails is applied to ensure that the solution is reliable, workable, and transparent. As topology optimization is a technological reality, to delay its natural implementation would distort price signals and mislead investors. This NOGRR and NPRR1198 were developed jointly with ERCOT Staff to ensure that these operational capabilities are implemented in a manner that meets the following criteria: **Transparency.** The EAP process is transparent - reconfiguration plans are published and Market Participants can comment on them. The information and software required to identify reconfiguration solutions and their impacts are available to all Market Participants. **Predictability.** Congestion patterns and their impacts are generally well known and changes can be anticipated by Market Participants. Approval criteria can be established such that expectations are clear and consistent. Reconfigurations can easily be reversed. EAPs have pre-determined beginning and ending times that make the impact or reconfigurations easily predictable by any Market Participant. **Equity.** The choices of Market Participants are made with the understanding that market conditions may change for a range of reasons including technological improvements. Suboptimal operation of the transmission network is inequitable to Customers as they bear the burden of transmission congestion.

	Workability. The validation of EAP requests can be performed rapidly using existing processes and without major investment in additional capabilities or staffing resources. Based on experience in other regions, the number of EAP submissions would be limited (i.e., less than 2% of the number of transmission outage ticket submissions that ERCOT supports today). If EAPs were to become burdensome, the submission process could be streamlined to reduce workload or two additional ERCOT Staff may be warranted and justified given the significant benefits the process would provide to the ERCOT System. Further, EAP submissions would bear the burden of proving benefits, thus preventing spurious submissions. **Reliability.** ERCOT already leverages reconfigurations with CMPs for overload mitigation, showing their reliability value even during extreme system conditions. Adoption of EAPs will further improve reliability for issues not covered in current CMPs. **Planning.** Depending on the situation, topology reconfigurations can be deployed either as temporary solutions to congestion problems while transmission upgrades are pending or as longer-term solutions in areas where further transmission capacity need is not anticipated. This distinction makes it possible to account only for long-term topology reconfigurations that are approved as such by ERCOT and/or the Transmission Service Providers (TSPs) in the planning process.
ROS Decision	On 10/5/23, ROS voted unanimously to table NOGRR258 and refer the issue to the Operations Working Group (OWG) and Network Data Support Working Group (NDSWG). All Market Segments participated in the vote. On 4/4/24, ROS voted to recommend approval of NOGRR258 as amended by the 3/8/24 LCRA comments as revised by ROS. There were four abstentions from the Cooperative (STEC), Independent Generator (Calpine), Independent Power Marketer (IPM) (SENA), and Investor Owned Utility (IOU) (CNP) Market Segments. All Market Segments participated in the vote. On 5/2/24, ROS voted to endorse and forward to TAC the 4/4/24 ROS Report and the 4/30/24 Impact Analysis for NOGRR258. There were three abstentions from the Cooperative (STEC), Independent Generator (Calpine), IOU (CNP) Market Segments. All Market Segments participated in the vote.
Summary of ROS Discussion	On 10/5/23, participants reviewed NOGRR258 and raised concerns regarding the potential for gaming opportunities in the markets, and there was general agreement to refer the issue to OWG and NDSWG to discuss operational impacts and modeling issues.

	On 4/4/24, participants reviewed the 3/8/24 LCRA comments and ROS made non-substantive revisions to paragraph (2) of Section 11.8. On 5/2/24, participants reviewed the 4/30/24 Impact Analysis for NOGRR258.
TAC Decision	On 5/22/24, TAC voted to recommend approval of NOGRR258 as recommended by ROS in the 5/2/24 ROS Report. There were four abstentions from the Cooperative (STEC), Independent Generator (2) (Jupiter Power, Calpine) and IOU (CNP) Market Segments. All Market Segments participated in the vote.
Summary of TAC Discussion	On 5/22/24, there was no additional discussion beyond TAC review of the items below.
TAC Review/Justification of Recommendation	[X] Revision Request ties to Reason for Revision as explained in Justification [X] Impact Analysis reviewed and impacts are justified as explained in Justification [X] Opinions were reviewed and discussed [X] Comments were reviewed and discussed (if applicable) [ ] Other: (explain)
ERCOT Board Decision	On 6/18/24, the ERCOT Board voted unanimously to recommend approval of NOGRR258 as recommended by TAC in the 5/22/24 TAC Report.

Opinions	
Credit Review	Not applicable
Independent Market Monitor Opinion	IMM supports approval of NOGRR258.
ERCOT Opinion	ERCOT supports approval of NOGRR258.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NOGRR258 and believes that it provides a positive market impact by leveraging ERCOT's existing CMP process to mitigate critical transmission congestion impacts.

Sponsor

Board Report

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Market Segment	Independent Generator

Market Rules Staff Contact	
Name	Erin Wasik-Gutierrez
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Comments Received	
Comment Author	**Comment Summary**
DC Energy 102323	Addressed market transparency aspects of NOGRR258 and revised language to ensure there is sufficient time for Market Participants and TOs to review and provide substantive comments for RAP and EAP submissions to ERCOT
EDF Renewables 103023	Integrated feedback received in stakeholder meeting discussions and written comments to address concerns and improve transparency
STEC 111423	Added a provision reflecting language changes discussed by the OWG and NDSWG requiring ERCOT to verify that a RAP does not result in radial generation or increase the risk of dispatchable generation under a N-1 contingency
Oncor 012224	Proposed NOGRR258's scope be limited to EAPs, established a $5 million threshold for EAPs and made various clarifying revisions to the language
EDF Renewables 021624	Made incremental changes to the 1/24/24 Oncor comments
LCRA 021624	Supported the goals of NOGRR258 and NPRR1198 and made incremental changes to the 2/16/24 LCRA comments
LCRA 030824	Made additional changes to the 2/16/24 LCRA comments

Sandy Creek Associates 031224	Supported NOGRR258 and NPRR1198, specifically, the 9/6/23 IMM comments to NPRR1198, 2/16/24 EDF Renewables comments and the 2/16/24 and 3/8/24 LCRA comments
AWEP 032824	Revised the 3/8/24 LCRA comments removing "if applicable" in Section 11.8 and added new paragraph (2)(i) in Section 11.8 to make clear dropping Loads in EAPs for economic reasons is not allowed
EDF Renewables 040124	Addressed the 3/28/24 AWEP comments and explained the revisions are unnecessary

Market Rules Notes

None

Proposed Guide Language Revision

11 CONSTRAINT MANAGEMENT PLANS AND REMEDIAL ACTION SCHEMES

11.1- Introduction

(1) Constraint Management Plans (CMPs) are developed in accordance to the guidelines set forth in the sections below, and are defined in Protocol Section 2.1, Definitions. CMPs include, but are not limited to the following:

(a) Remedial Action Plans (RAPs) which are modeled in Network Security Analysis (NSA) where practicable;

(b) Automatic Mitigation Plans (AMPs) which are modeled in NSA where practicable;

(c) Pre-Contingency Action Plans (PCAPs);

(d) Extended Action Plans (EAPs);

(~~d~~e) Temporary Outage Action Plans (TOAPs); and

(~~e~~f) Mitigation Plans.

(2) When developing CMPs, ERCOT shall first attempt to utilize the 15-Minute Rating of the impacted Transmission Facilities, where available, to develop RAPs such that the ERCOT Transmission Grid is utilized to the fullest extent.

[NOGRR215: Insert paragraph (3) below upon system implementation and renumber accordingly:]

(3) Remedial Action Schemes (RASs) and/or AMPs may also be implemented in order to allow Generation Resources described in paragraph (3) of Planning Guide Section 4.1.1.7, Minimum Deliverability Criteria, to meet the minimum deliverability criteria in Planning Guide Section 4.1.1.7, or Transmission Facilities that would otherwise be subject to restrictions to operate without such restrictions.

(3) ~~RAPs and EAPs may be utilized to address avoidable congestion prior tothat is resolvable by Security-Constrained Economic Dispatch (SCED) on facilitate the market use of the ERCOT Transmission Grid for constraints that have resulted in: over $5$1 million of congestion cost over a period of three consecutive months, in a given month within the past 2436 months.~~EAPs may be proposed by any Market Participant or developed by ERCOT and can be utilized for reliability or economic reasons. EAPs proposed for reliability reasons may have thermal constraints that do not have a Security-Constrained Economic Dispatch (SCED) solution. EAPs proposed for economic reasons may have thermal constraints that are resolvable by SCED but result in high congestion costs. If an EAP is proposed primarily for economic reasons, the avoidable congestion must have resulted in:

(a) Over $2 million of congestion cost in a given month within the past 36 months; or

(b) $5 million of congestion cost over any three months within the past 36 months~~;~~ ~~or~~.

~~(c) Are reasonably expected to result in similar costs under future conditions within the next 12 months as validated by ERCOT.~~

~~(4) Prior to submitting a RAPs or EAPs must be submitted to ERCOT for review to facilitate the market use of the ERCOT Transmission Grid. ERCOT, the proposing Entity must review the design with impacted Transmission Operators (TOs) and the proposing Entity directly operationally impacted Resource Entities to verify the feasibility of the submission. Impacts resulting from market clearing processes shall not constitute a direct operational impact under this paragraph.~~

~~(5) For a RAP or EAP submitted for review to facilitate the market use of the ERCOT Transmission Grid, all Generation Resource Entities that would be directly affected operationally by the proposed actions must be part of the submitting parties. Impacts resulting from market clearing processes shall not constitute a direct operational impact under this paragraph.~~(4465) ERCOT shall provide notification to the market of any approved, amended, or removed CMP or Remedial Action Scheme (RAS). ERCOT shall provide notification to the market of any RAP, AMP, or RAS that cannot be modeled in the Network Operations Model. ERCOT shall post to the Market Information System (MIS) Secure Area all CMPs and RASs and any unmodeled CMPs or RASs.

~~(54) ERCOT shall provide notification to the market of any proposed RASs or PCAPs on the MIS Secure Area.~~

(56~~7~~6) ERCOT is not required to provide notification to the market of any proposed TOAPs.

(67~~8~~7) All submittals related to CMPs or RASs must be emailed to ras_cmp@ercot.com.

11.4 Remedial Action Plan

(1) Remedial Action Plans (RAPs) are defined in Protocol Section 2.1, Definitions, and may be relied upon in allowing additional use of the transmission system in Security-Constrained Economic Dispatch (SCED). Normally, it is desirable that a Transmission Service Provider (TSP) constructs Transmission Facilities adequate to eliminate the need for any RAP; however, in some circumstances, such construction may be unachievable in the available time frame.

(2) RAPs ~~for reliability~~ must:

(a) Be coordinated by ERCOT with all Transmission Operators (TOs) and Resource Entities included in the RAP, and approved by ERCOT;

(b) Be limited to the time required to construct replacement Transmission Facilities; however, the RAP will remain in effect if ERCOT has determined the replacement Transmission Facilities to be impractical;

(c) Comply with all applicable requirements in the Protocols and applicable North American Electric Reliability Corporation (NERC) Reliability Standards;

(d) Clearly define and document TOs and Resource Entities included in the RAP actions;

(e) Must be able to resolve the issue for which it was designed over the range of conditions that might reasonably be experienced;

(f) Be executed by the TOs and/or Resource Entities;

(g) Have a 15-minute Rating greater than the Normal and Emergency Ratings for the Transmission Facilities it intends to resolve;

(h) Be defined in the Network Operations Model and considered in the SCED and Reliability Unit Commitment (RUC) processes. RAPs that cannot be modeled using ERCOT's existing infrastructure shall be rejected unless the Technical Advisory Committee (TAC) approves a plan to work around the infrastructure problem; and

(i) Not include generation re-Dispatch or Load shed.

~~(3) Prior to approving a RAP proposal to facilitate the market use of the ERCOT Transmission Grid, ERCOT and the impacted TOs must verify that the RAP:~~

~~(a) Meets all of the criteria established in paragraph (2) above;~~

~~(b) Does not result in radial Load;~~

~~(c) Does not create new binding constraints or increase flow on any existing binding constraint by more than 1%;~~

~~(d) Does not negatively impact any Generic Transmission Constraints (GTCs), decrease Generic Transmission Limits (GTLs) or create new instability situations;~~

~~(e) Has not been previously rejected, unless there have been major changes to the system configuration or RAP proposal; and~~

~~(f) Provides more than $1 million savings to total production cost or congestion cost with the RAP action in place compared to generation re-Dispatch alone. This can be established either by using annual production cost model simulation or other methods acceptable to ERCOT.~~

(3~~3~~4) An approved RAP may be executed immediately after a contingency by the TOs and Resource Entities included in the RAP without instruction by ERCOT or shall be executed upon direction by ERCOT.

(4~~4~~5) ERCOT shall conduct a review of each existing RAP annually or as required by changes in system conditions to ensure its continued effectiveness. Each review shall proceed according to a process and timetable documented in ERCOT Procedures.

(5~~5~~6) ERCOT may approve the expiration of a RAP after consultation with the TOs and Resource Entities included in the RAP. ERCOT shall modify its reliability constraints to recognize the unavailability of the RAP.

11.4.1 Remedial Action Plan Process

(1) RAPs~~, including RAPs to facilitate the market use of the ERCOT Transmission Grid,~~ may be proposed by any Market Participant or may be developed by ERCOT. For RAPs submitted by Market Participants not registered as a TSP:

(a) ERCOT shall post RAPs submitted by a Market Participant not registered as a TSP on the Market Information System (MIS) Secure Area as soon as practicable, but no later than five Business Days of receipt.

(b) ERCOT shall provide a five Business Day~~30~~45~~five Business Dday~~ comment period from the date when the proposed RAP under review is posted by ERCOT unless notice of a shorter comment period is provided.

(c) ERCOT shall consider all comments received within the five Business Day~~3045five Business Dday~~ comment period on the proposed RAP, along with its own evaluation and those of the Transmission Facility owners, and either approve, modify or reject that proposed RAP.

(d) When a ~~If a~~ proposed RAP is approved~~accepted,~~ modified, or rejected, ERCOT shall post an explanation for the approval or rejection, or a description of the modification. If the RAP is approved the posting shall include the start date of the RAP.

11.6 Pre-Contingency Action Plans

(1) Pre-Contingency Action Plans (PCAPs) are defined in Protocol Section 2.1, Definitions, and are implemented in anticipation of a contingency. Normally, it is desirable that a Transmission Service Provider (TSP) construct Transmission Facilities adequate to eliminate the need for any PCAP; however, in some circumstances, such construction may be unachievable in the available time frame.

(2) A PCAP may be proposed by any Market Participant, and be approved by ERCOT and the Transmission Operator (TO) included in the PCAP prior to implementation. PCAPs must:

(a) Be coordinated with the TOs included in the PCAP;

(b) Be limited in use to the time required to construct replacement Transmission Facilities and until such Facilities are placed in-service, or the PCAP is no longer needed; however, the PCAP will remain in effect if ERCOT has determined the replacement Transmission Facilities to be impractical;

(c) Comply with all requirements of the Protocols and applicable North American Electric Reliability Corporation (NERC) Reliability Standards;

(d) Clearly define and document TO actions;

(e) Be executed by TOs; and

(f) Not include generation re-Dispatch or Load shed.

(3) An approved PCAP may be executed immediately prior to a contingency by the TO without instruction by ERCOT, or shall be executed upon direction by ERCOT.

(4) All proposed, approved, amended, and removed PCAPs shall be managed in accordance with paragraph (44~~65~~) of Section 11.1, Introduction.

(5) ERCOT may limit the quantity of PCAPs that are used.

11.8 Extended Action Plans (EAPs)

(1) ~~An~~ Extended Action Plans (EAPs) ~~may be proposed by any Market Participant or developed by ERCOT, and~~ must be approved prior to implementation by ERCOT, the Transmission Operators (TOs) that operate the affected equipment~~included in the EAP~~, and Resource Entities that are directly impacted operationally ~~impacted Resource Entities~~. Impacts resulting from price and Dispatch changes due to market clearing processes shall not constitute a direct operational impact under this section. EAPs must:

(a) Be accepted ~~as feasible~~ by ~~coordinated with~~ the Resource Entities and TOs that are directly impacted operationally by~~included in~~ the EAP;

(b) Be restored to normal configuration when either:

(i) A transmission project intended to address the congestion is placed in-service, if such a project has been made public and it was identified by either the TO during the initial EAP review, or by a Transmission Service Provider (TSP) during the EAP comment period; or

(ii) A period of temporary congestion is expected to end, if such temporary congestion and its estimated end date were identified during the initial EAP review. For chronic congestion which does not have an identified transmission project solution or expected end, an end date for the EAP must be proposed as if it is temporary congestion.

~~limited in use to the time required to evaluate, approve, and construct replacement Transmission Facilities until such Transmission Facilities are placed in-service, or the EAP is no longer needed. In cases where the EAP mitigates temporary congestion, the use of an EAP may be limited to the duration of the temporary congestion, or until the EAP is no longer needed;~~

(c) Comply with all requirements of the Protocols and applicable North American Electric Reliability Corporation (NERC) Reliability Standards;

(d) Clearly define and document TO actions;

(e) Be executed by TOs; and

(f) Not include generation re-Dispatch or Load shed.

(2) Prior to approving an EAP proposal ~~to address avoidable congestion prior tothat is resolvable by Security-Constrained Economic Dispatch (SCED)~~for economic reasons on~~facilitate the market use of~~ the ERCOT Transmission Grid, ERCOT ~~and the impacted Resource Entities and TOs~~ must verify that the EAP:

(a) Meets all of the criteria in paragraph (1) above;

(b) ~~Does not result in~~~~Minimizes the use of~~ Does not result in radial Load ~~Radial Load will be permitted only at ERCOT and TO's discretion.~~;

(c) Does not negatively impact current or scheduled Transmission Facility Outages;

(~~c~~d) Does not create new binding thermal constraints or voltage violations, or increase flow on any existing binding constraint by more than 2% for 69 kV and 1% for 1~~38~~15 kV and above;

(~~d~~e) Does not negatively impact any Generic Transmission Constraints (GTCs),decrease Generic Transmission Limits (GTLs), or create new instability situations;

(~~e~~f) Provides more than $15~~$1~~ million savings to total production cost or total congestion cost with the EAP action in place compared to generation re-Dispatch alone. This can be established either by using annual production cost model simulation or other methods acceptable to ERCOT;

(~~g~~g) Limits the action to changing the normal status of circuit breaker~~transmission equipment~~ at up to ~~two~~three substations;

(~~h~~h) If applicable, is limited to a post-contingency generation trip of no more than ERCOT frequency bias; ~~and~~

(~~i~~i) Does not impact the ability of a Resource to meet its minimum deliverability criteria described in Planning Guide Section 4.1.1.7, Minim~~i~~um Deliverability Criteria~~.~~; and

(~~i~~j) Has not been previously rejected by ERCOT for disqualification under criteria in paragraphs (b) through (i) above, unless there have been major changes to the system configuration or EAP proposal~~;~~.

(3) An approved EAP may be executed ~~immediately prior to a contingency~~ by the TO in coordination with~~without instruction by~~ ERCOT, on the effective date of the EAP~~or shall be executed upon direction by ERCOT~~.

(4) All proposed, approved, amended, and removed EAPs shall be managed in accordance with paragraph (4~~6~~) of Section 11.1, Introduction.

(5) ERCOT may limit the quantity of EAPs that are used.

(6) ERCOT may reject proposals that fail to practicably assess impact to operations and reliability.

(7) The implementation of an approved EAP may be temporarily suspended ~~for~~by the TO or by ERCOT for reliability reasons, or for the duration of a ~~t~~Transmission Facility ~~o~~Outage if the EAP interferes with a TO's ability to take the outage. The existence of an EAP

shall not, in and of itself, prevent a requested Transmission Facility Outage from being approved by ERCOT.

(8) ERCOT shall conduct a review of each existing EAP annually or as required by changes in system conditions to ensure its continued effectiveness. Each review shall proceed according to a process and timetable documented in ERCOT procedures.

11.8.1 Extended Action Plan (EAP) Process

(1) EAPs proposed by a Transmission and/or Distribution Service Provider (TDSP) primarily for reliability reasons have an expedited review and are not subject to the process outlined in this section.~~EAPs may be proposed by any Market Participant or may be developed by ERCOT. For~~ EAPs proposed primarily for economic reasons need to follow the process outlined below in addition to the requirements in Section 11.8, Extended Action Plans (EAPs)~~ submitted by Market Participants not registered as a Transmission Service Provider (TSP)~~:

(a) The EAP must be submitted to ERCOT for initial review. ERCOT must provide the submission of qualified EAPs to impacted TOs and Resource Entities directly impacted operationally. Impacts resulting from price and Dispatch changes due to market clearing processes shall not constitute a direct operational impact under this paragraph.

(i) Impacted TOs, and Resource Entities directly impacted operationally, will provide either a concurrence with or an objection to the proposed EAP to ERCOT in writing within 30~~45~~ days of receipt, and may request additional time if necessary while making reasonable efforts to consider proposed EAPs as soon as possible; ~~and~~

(ii) Impacted TOs may limit the quantity of EAPs they have under evaluation, on the basis of undue or excessive work load, and will include this as the reason for objection to an EAP, if applicable; and

(iii) An objection by either an impacted TO~~,~~ or a Resource Entity directly impacted operationally, will result in an initial rejection of the proposed EAP by ERCOT.

(b~~a~~) ~~ERCOT shall post~~ EAPs submitted by a Market Participant ~~not registered as a TSP~~ will be posted on the Market Information System (MIS) Secure Area by ERCOT within five Business Days of receipt of a complete submission~~ERCOT's receipt of written concurrence from both the impacted TO(s) and Resource Entities as described in paragraph (1)(a) above~~~~receipt~~.

(c~~b~~) ERCOT will provide a 30~~45~~ ~~five Business D~~day comment period from the date ~~when~~ the proposed EAP ~~under review~~ is posted to the MIS Secure Area by ERCOT, unless notice of a shorter comment period is provided by ERCOT.

(~~d~~e) ERCOT shall consider all comments received within the 30~~45~~ ~~five Business D~~day comment period on the proposed EAP, along with its own evaluation and those of the Transmission Facility owners, and either approve, modify, or reject the proposed EAP within 15 days, unless extended by ERCOT.

(~~e~~d) When~~If~~ a proposed EAP is approved, modified or rejected, ERCOT shall post an explanation for the approval or rejection, or a description of the modification within five Business Days of its determination. If the EAP is approved, the posting shall include the start date and end date or associated Transmission Facility change that will determine the end date of the EAP.

(2) The implementation and management of EAPs will be facilitated through the Network Operations Model Change Request (NOMCR) and Outage scheduling processes as follows:

(a) A NOMCR will be submitted by the applicable TO or Resource Entity to implement an approved EAP in the Network Operations Model. This NOMCR will be submitted prior to the EAP's start date and during the appropriate NOMCR production model load schedule. The EAP start date should align with the NOMCR production model load date, and if these two dates differ, Transmission Facility Outages will be submitted by the applicable TO or Resource Entity to manage interim configuration changes until the submitted NOMCR implements the EAP in the Network Operations Model.

(b) If a TO or ERCOT identifies that an approved EAP will create a conflict with a current or scheduled Transmission Facility Outage or other system conditions, the applicable TO or Resource Entity will reverse the EAP configuration by submitting the necessary Transmission Facility Outage(s) and/or by utilizing the NOMCR process to address the timeframe for which the conflict is expected to exist. ERCOT shall also post any such EAP changes to the MIS Secure Area.

(c) A NOMCR will be submitted by the applicable TO or Resource Entity to reverse an EAP prior to the scheduled EAP end date and during the appropriate NOMCR production model load schedule. Transmission Facility Outages may also be used to manage interim configuration changes before the NOMCR takes effect, if necessary.

(3) A Market Participant or ERCOT may propose that an existing EAP be suspended, modified, or extended. ERCOT will process any proposed EAP modifications or extensions as described by paragraphs (1)(a) through (e) above.

ERCOT Impact Analysis Report

NOGRR Number	258	NOGRR Title	Related to NPRR1198, Congestion Mitigation Using Topology Reconfigurations
Impact Analysis Date	April 30, 2024		
Estimated Cost/Budgetary Impact	None.		
Estimated Time Requirements	No project required. This Nodal Operating Guide Revision Request (NOGRR) can take effect upon implementation of Nodal Protocol Revision Request (NPRR) 1198, Congestion Mitigation Using Topology Reconfigurations.		
ERCOT Staffing Impacts (across all areas)	Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	No impacts to ERCOT computer systems.		
ERCOT Business Function Impacts	No impacts to ERCOT business functions.		
Grid Operations & Practices Impacts	No impacts to ERCOT grid operations and practices.		

Evaluation of Interim Solutions or Alternatives for a More Efficient Implementation
None offered.

Comments
There are no additional impacts to this NOGRR beyond what was captured in the Impact Analysis for NPRR1198.

Board Report

PGRR Number	112	PGRR Title	Dynamic Data Model and Full Interconnection Study (FIS) Deadline for Quarterly Stability Assessment
Date of Decision	June 18, 2024		
Action	Recommended Approval		
Timeline	Normal		
Estimated Impacts	Cost/Budgetary: Less than $10K (O&M) Project Duration: No project required		
Proposed Effective Date	December 1, 2024		
Priority and Rank	Not applicable		
Planning Guide Sections Requiring Revision	5.3.2.5, FIS Report and Follow-up 5.3.5, ERCOT Quarterly Stability Assessment		
Related Documents Requiring Revision/Related Revision Requests	None		
Revision Description	This Planning Guide Revision Request (PGRR) establishes requirements for Interconnecting Entities (IEs) to submit dynamic data models and for Transmission Service Providers (TSPs) to submit final Full Interconnection Studies (FISs) for approval at least 45 days prior to the quarterly stability assessment deadline. Projects will not be qualified for the quarterly stability assessment if dynamic data models and final FISs are submitted less than 45 days prior to the deadline. This PGRR also establishes that an IE must notify ERCOT and lead TSP(s) of changes to FIS assumptions that occur after FIS completion and before Initial Synchronization. It further clarifies that ERCOT shall not include a Generation Resource or Settlement Only Generator (SOG) in a quarterly stability assessment if certain requirements are not met prior to the quarterly stability assessment deadline. ERCOT will be required to notify a Generation Resource or SOG if it is ineligible be included in a quarterly stability assessment for which it has timely submitted data.		
Reason for Revision	☐ Strategic Plan Objective 1 – Be an industry leader for grid reliability and resilience		

Board Report

	☐ 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	In accordance with Sections 5, Generator Interconnection or Modification and 6, Data/Modeling, IEs must submit dynamic data models and model quality test reports for approval ahead of the quarterly stability assessment deadlines established in paragraph (2) of Section 5.3.5. Paragraph (4)(b)(i) of Section 5.3.5 recommends that the IE submit dynamic data models 30 days prior to the quarterly stability assessment deadline. However, in most cases, IEs submit or update the models only a week or two prior to the deadline, leaving ERCOT with a limited time period for reviewing such models. Additionally, TSPs have sometimes submitted FIS studies only a week or two before the quarterly stability assessment deadline, leaving ERCOT little time to review the study results before the deadline. Market Participants have raised concerns with their dynamic data models not being evaluated in time for them to address comments prior to the quarterly stability assessment deadline. This PGRR addresses Market Participant and ERCOT concerns by requiring the dynamic data model and final FISs to be submitted at least 45 days prior to the quarterly stability assessment deadline. This will provide ERCOT with sufficient time to review the submissions and send comments to the IE and will also provide the IE with sufficient time to address comments prior to the quarterly stability assessment deadline. This PGRR will also ensure that a Generation Resource or SOG has satisfied the prerequisites for a quarterly stability assessment before ERCOT includes it in such an assessment.

Board Report

ROS Decision	On 10/5/23, ROS voted unanimously to table PGRR112 and refer the issue to the Planning Working Group (PLWG) and Dynamics Working Group (DWG). All Market Segments participated in the vote. On 3/7/24, ROS voted unanimously to recommend approval of PGRR112 as amended by the 1/17/24 ERCOT comments. All Market Segments participated in the vote. On 4/4/24, ROS voted unanimously to endorse and forward to TAC the 3/7/24 ROS Report and the 4/1/24 Revised Impact Analysis for PGRR112 with a recommended effective date of December 1, 2024. All Market Segments participated in the vote.
Summary of ROS Discussion	On 10/5/23, ERCOT Staff presented PGRR112. Participants highlighted areas for potential improvements to the proposed language to provide clarity and referred PGRR112 to the PLWG and DWG for further discussion. On 3/7/24, PLWG leadership reported the working group supports PGRR112 as modified by the 1/17/24 ERCOT comments. On 4/4/24, participants reviewed the 4/1/24 Revised Impact Analysis. Market Participants requested a December 1, 2024 implementation date to allow them time to accommodate the new deadline requirements.
TAC Decision	On 4/15/24, TAC voted unanimously to recommend approval of PGRR112 as recommended by ROS in the 4/4/24 ROS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 4/15/24, there was no additional discussion beyond TAC review of the items below.
TAC Review/Justification of Recommendation	☒ Revision Request ties to Reason for Revision as explained in Justification ☒ Impact Analysis reviewed and impacts are justified as explained in Justification ☒ Opinions were reviewed and discussed ☒ Comments were reviewed and discussed (if applicable) ☐ Other: (explain)
ERCOT Board Decision	On 6/18/24, the ERCOT Board voted unanimously to recommend approval of PGRR112 as recommended by TAC in the 4/15/24 TAC Report.

Board Report

Opinions	
Credit Review	Not applicable
Independent Market Monitor Opinion	IMM has no opinion on PGRR112.
ERCOT Opinion	ERCOT supports approval of PGRR112.
ERCOT Market Impact Statement	ERCOT Staff has reviewed PGRR112 and believes that requiring the dynamic data model and final FISs to be submitted at least 45 days prior to the quarterly stability assessment deadline will have a market positive impact by providing Market Participants time to address ERCOT's comments from the evaluation of dynamic data models prior to the quarterly stability assessment deadline.

Sponsor	
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Market Segment	Not Applicable

Market Rules Staff Contact	
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Comments Received	
Comment Author	**Comment Summary**
LCRA 103123	Proposed modifications to require TSPs to submit the preliminary FIS studies at least 45 days prior to the applicable quarterly stability assessment deadline

Board Report

ERCOT 011724	Agreed to change the deadline for submission of a final FIS from 30 Business Days to 45 days prior to the quarterly stability assessment deadline and proposed revisions to establish that an IE be required to notify ERCOT and the lead TSP(s) of changes to FIS assumptions that occur after FIS completion and before Initial Synchronization

Market Rules Notes

Please note the baseline Planning Guide language in Section 5.3.5 was updated to include paragraphs (5) and (6) which were inadvertently omitted in the original submission of this PGRR.

Please note that the following PGRR(s) also proposes revisions to the following section(s):

- PGRR115, Related to NPRR1234, Interconnection Requirements for Large Loads and Modeling Standards for Loads 25 MW or Greater
  - Section 5.3.5

Proposed Guide Language Revision

5.3.2.5 FIS Report and Follow-up

(1) The TSP(s) will submit to ERCOT and to the other TSP(s) via the online RIOO system a preliminary report of findings and recommendations for each of the FIS elements~~ at least 45 days prior to the applicable quarterly stability assessment deadline as defined in paragraph (2) of Section 5.3.5, ERCOT Quarterly Stability Assessment~~.

(2) Any questions, comments, proposed revisions, or clarifications by any party shall be made in writing to the TSP(s) within ten Business Days after the issuance of each study report, which may cover one or more study elements. ERCOT can extend this review period by an additional 20 Business Days and an email will be sent to notify the affected TSP(s) and the IE that it needs additional time to review the report.

(3) After considering the information received from ERCOT and other TSPs, the study element(s) report will be deemed complete and a final report shall be provided, via the online RIOO system, to ERCOT and all TSPs. The TSP(s) conducting the FIS shall submit via the online RIOO system, the SSR analysis, if required, as a separate document from the remainder of the report.

(4) Each final study element report will be available via the online RIOO system after the report has been deemed complete and marked "final" and will be posted to the MIS Secure Area within ten Business Days. Coincident with posting of the final FIS study element reports to the MIS Secure Area, ERCOT will notify the TSP and the IE when each study element report is posted. The TSP shall provide a copy of each final report to the IE upon request.

(5) The study element(s) report shall not contain sensitive information including, but not limited to, confidential plant design information including stability study model data and parameters and contingencies causing instability. The TSP(s) shall provide this information to ERCOT and other TSP(s) upon request.

(6) The TSP issuing the final FIS element(s) report shall indicate that the report is the final report required by the FIS. At the end of the ten Business Day review period following the issuance of the final FIS element(s) report, the FIS will be deemed complete and the IE and TSP may execute an SGIA.

(7) The final FIS element(s) report shall be deemed complete and marked "final" via the online RIOO system at least 45 days prior to the quarterly stability assessment deadline defined in paragraph (2) of Section 5.3.5, ERCOT Quarterly Stability Assessment.

(~~7~~8) Should the IE wish to proceed with any proposed transmission-connected project, the IE must execute a new or amended SGIA with the appropriate TSP within 180 days following the completion of the FIS (includes all major study element(s) reports). Failure to do so may result in a cancellation as described in Section 5.2.6, Project Cancellation Due to Failure to Comply with Requirements.

(~~8~~9) ~~If d~~During the time after the FIS is completed and before Initial Synchronization, the IE shall notify both ERCOT and the lead TSP(s) of any changes to the assumptions used for the FIS along with a detailed written explanation of why the changes were made. If the changes~~occur that~~ substantially differ from the assumptions used for the FIS, ERCOT and the TSP(s) shall determine the impact of the changes on the results of the FIS and, if applicable, SSR studies. If the changes are determined by ERCOT and lead TSP(s) to have the potential to materially alter the conclusions documented in the FIS, the lead TSP(s) will make appropriate modifications to one or more FIS study elements. The updated FIS reports will be submitted via the online RIOO system. Any questions, comments, proposed revisions, or clarifications by any party shall be made in writing to the TSP(s) within ten Business Days after the issuance of an updated study report. Initial Synchronization of the generator may be delayed pending completion of these modifications to the FIS.

5.3.5 ERCOT Quarterly Stability Assessment

Commented [EWG1]: Please note PGRR115 also proposes revisions to this section.

(1) ERCOT shall conduct a stability assessment every three months to assess the impact of planned large generators connecting to the ERCOT System. The assessment shall derive the conditions to be studied with consideration given to the results of the FIS stability studies for large generators, with planned Initial Synchronization in the period under study. ERCOT may study conditions other than those identified in the FIS stability studies.

(2) Large generators that are not included in the assessment as described in this Section as result of the IE failing to meet the prerequisites by the deadlines as listed in the table below will not be eligible for Initial Synchronization during that three-month period. The

timeline for the quarterly stability assessment shall be in accordance with the following table:

Generator Initial Synchronization Date	Last Day for an IE to meet prerequisites as listed in paragraph (4) below	Completion of Quarterly Stability Assessment
Upcoming January, February, March	Prior August 1	End of October
Upcoming April, May, June	Prior November 1	End of January
Upcoming July, August, September	Prior February 1	End of April
Upcoming October, November, December	Prior May 1	End of July

(3) If the last day for an IE to meet prerequisites or if completion of the quarterly stability assessment as shown in the above table falls on a weekend or holiday, the deadline will extend to the next Business Day.

(4) The following p~~P~~rerequisites shall~~to~~ be satisfied prior to a~~the~~ large generator being included in the quarterly stability assessment:

(a) The generator has met the requirements of Section 6.9, Addition of Proposed Generation to the Planning Models.

(b) The IE has provided all generator data in accordance with the Resource Registration Glossary, Planning Model column, including but not limited to steady state, system protection and stability models.

(i) The IE shall submit the final dynamic data model ~~will be reviewed by ERCOT prior to the quarterly stability assessment and should~~shall ~~be submitted by the IE~~ at least ~~30~~45 ~~Business~~ ~~d~~Ddays ~~before~~ prior to the quarterly stability assessment deadline described in paragraph (2) above. If ~~either the IE does not submit the required dynamic data model at least 30 Business Days before the~~ ERCOT is unable to complete its review prior to the quarterly stability assessment deadline~~or Iif this review cannot be completed prior to the quarterly stability assessment deadline~~, ERCOT ~~may refuse to allow Initial Synchronization of~~shall not include the Generation Resource or Settlement Only Generator (SOG) in that~~the three month period associated with the~~ quarterly stability assessment ~~deadline~~. ~~ERCOT shall include the Generation Resource or SOG in the next quarterly stability assessment period provided that the review of the dynamic data model has been completed prior to the next quarterly stability assessment's deadline.~~

(ii) Changes to the dynamic data model after the stability study is deemed complete may subject the Generation Resource or SOG to modification of one or more FIS study elements as defined in paragraph (9) of Section 5.3.2.5, FIS Report and Follow-up. If ERCOT and the lead TSP(s) determine that modifications to one or more FIS study elements are required, then ERCOT shall not include the Generation Resource or SOG in a quarterly stability assessment until the revised FIS has been completed in accordance with paragraph (4)(c)(i) below.

(iii) If an IE submitted a final dynamic data model at least 45 days prior to the quarterly stability assessment deadline but ERCOT determines that the Generation Resource or SOG is ineligible to be included in a quarterly stability assessment pursuant to paragraphs (4)(b)(i) or (4)(b)(ii) above, ERCOT will send a notification to the IE.

(c) The following elements must be complete:

(i) ~~Final~~ Final FIS studies~~, which the TSP must have submitted in the online RIOO system at least 30 Business Days prior to the quarterly stability assessment deadline~~, which the TSP must have submitted via the online RIOO system at least 45 days prior to the quarterly stability assessment deadline;

(ii) Reactive Power Study; and

(iii) System improvements or mitigation plans that were identified in these studies as required to meet the operational standards established in the Protocols, Planning Guide, Nodal Operating Guides, and Other Binding Documents prior to synchronizing the generator.

(d) The data used in the studies identified in paragraph (4)(c) above is consistent with data submitted by the IE as required by Section 6.9.

(5) At any time following the inclusion of a large generator in a stability assessment, but before the Initial Synchronization of the generator, if ERCOT determines, in its sole discretion, that the generator no longer meets the prerequisites described in paragraph (4), or that an IE has made a change to the design of the generator that could have a material impact on ERCOT System stability, then ERCOT may refuse to allow Initial Synchronization of the generator, provided that ERCOT shall include the generator in the next quarterly stability assessment period that commences after identification of the material change or after the generator meets the prerequisites specified in paragraph (4), as applicable. If ERCOT determines, in its sole discretion, that the change to the design of the generator would not have a material impact on ERCOT System stability, then ERCOT may not refuse to allow Initial Synchronization of the generator due to this change.

(6) ERCOT shall post to the MIS Secure Area a report summarizing the results of the quarterly stability assessment within ten Business Days of completion.

Revised ERCOT Impact Analysis Report

PGRR Number	**112**	**PGRR Title**	**Dynamic Data Model and Full Interconnection Study (FIS) Deadline for Quarterly Stability Assessment**
Impact Analysis Date	April 1, 2024		
Estimated Cost/Budgetary Impact	Less than $10k, which will be absorbed by the Operations & Maintenance (O&M) budgets of affected department.		
Estimated Time Requirements	No project required. This Planning Guide Revision Request (PGRR) can take effect following Public Utility Commission of Texas (PUCT) approval. See Comments.		
ERCOT Staffing Impacts (across all areas)	Implementation Labor: 100% ERCOT; 0% Vendor Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	The following ERCOT systems would be impacted: • Resource Integration and Ongoing Operations (RIOO) 100%		
ERCOT Business Function Impacts	ERCOT will update its business processes to implement this PGRR.		
Grid Operations & Practices Impacts	No impacts to ERCOT grid operations and practices.		

Evaluation of Interim Solutions or Alternatives for a More Efficient Implementation
None offered.

Comments
ERCOT plans to manually implement PGRR112 until RIOO changes can be implemented.

Board Report

PGRR Number	113	PGRR Title	**Related to NPRR1198, Congestion Mitigation Using Topology Reconfigurations**
Date of Decision	June 18, 2024		
Action	Recommended Approval		
Timeline	Normal		
Estimated Impacts	Cost/Budgetary: None Project Duration: No project required		
Proposed Effective Date	Upon implementation of Nodal Protocol Revision Request (NPRR) 1198, Congestion Mitigation Using Topology Reconfigurations		
Priority and Rank Assigned	Not applicable		
Planning Guide Sections Requiring Revision	3.1.4.1.1, Regional Transmission Plan Cases 4.1.1.2, Reliability Performance Criteria		
Related Documents Requiring Revision/Related Revision Requests	NPRR1198, Congestion Mitigation Using Topology Reconfigurations Nodal Operating Guide Revision Request (NOGRR) 258, Related to NPRR1198, Congestion Mitigation Using Topology Reconfigurations		
Revision Description	This Planning Guide Revision Request (PGRR) revises the Planning Guide to provide that ERCOT will first consider transmission needs without Constraint Management Plan (CMP) actions in its Regional Transmission Plan studies, and will then only model a CMP in the Regional Transmission Plan in certain limited circumstances. A CMP will not be planned to resolve a planning criteria performance deficiency unless it is expected that system conditions will change such that the CMP will no longer be needed within the next five years.		
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	In transmission planning studies, ERCOT does not use CMPs to resolve reliability criteria performance deficiencies, except in the limited circumstances described in this PGRR. Instead, transmission solutions are utilized to address the transmission needs identified in planning studies. During the stakeholder discussions for NPRR1198 and NOGRR258, stakeholders identified the need to clarify the Planning Guide language describing ERCOT's practices in modeling CMPs in planning studies. This PGRR clarifies and codifies the transmission planning assumptions related to CMPs.
ROS Decision	On 12/7/23, ROS voted unanimously to table PGRR113 and refer the issue to the Planning Working Group (PLWG). All Market Segments participated in the vote. On 4/4/24, ROS voted unanimously to recommend approval of PGRR113 as submitted. All Market Segments participated in the vote. On 5/2/24, ROS voted to endorse and forward to TAC the 4/4/24 ROS Report and the 4/30/24 Revised Impact Analysis for PGRR113. There was one abstention from the Independent Generator (Calpine) Market Segment. All Market Segments participated in the vote.
Summary of ROS Discussion	On 12/7/23, participants reviewed PGRR113. On 4/4/24, there was no discussion on PGRR113. On 5/2/24, participants reviewed the 4/30/24 Revised Impact Analysis for PGRR113.
TAC Decision	On 5/22/24, TAC voted to recommend approval of PGRR113 as recommended by ROS in the 5/2/24 ROS Report. There were four abstentions from the Cooperative (STEC), Independent Generator (2) (Jupiter Power, Calpine) and IOU (CNP) Market Segments. All Market Segments participated in the vote.
Summary of TAC Discussion	On 5/22/24, there was no additional discussion beyond TAC review of the items below.

Board Report

TAC Review/Justification of Recommendation	☒ Revision Request ties to Reason for Revision as explained in Justification ☒ Impact Analysis reviewed and impacts are justified as explained in Justification ☒ Opinions were reviewed and discussed ☒ Comments were reviewed and discussed (if applicable) ☐ Other: (explain)
ERCOT Board Decision	On 6/18/24, the ERCOT Board voted unanimously to recommend approval of PGRR113 as recommended by TAC in the 5/22/24 TAC Report.

Opinions	
Credit Review	Not applicable
Independent Market Monitor Opinion	IMM supports approval of PGRR113.
ERCOT Opinion	ERCOT supports approval of PGRR113.
ERCOT Market Impact Statement	ERCOT Staff has reviewed PGRR113 and believes that it provides a positive market impact by clarifying and codifying the transmission planning assumptions related to CMPs.

Sponsor	
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Cell Number	
Market Segment	Not Applicable

Market Rules Staff Contact	
Name	Erin Wasik-Gutierrez
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Board Report

Phone Number	413-886-2474

Comments Received	
Comment Author	**Comment Summary**
None	

Market Rules Notes

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

- PGRR115, Related to NPRR1234, Interconnection Requirements for Large Loads and Modeling Standards for Loads 25 MW or Greater
  - Section 4.1.1.2

Proposed Guide Language Revision

3.1.4.1.1 Regional Transmission Plan Cases

(1) The starting base cases for the Regional Transmission Plan development are created by removing all Tier 1, 2, and 3 projects that have not received RPG acceptance or, if applicable, ERCOT endorsement from the most recent SSWG base cases.

(2) ERCOT shall set all non-seasonal Mothballed Generation Resources to out of service in the Regional Transmission Plan reliability base cases. ERCOT shall add proposed Generation Resources that have met the criteria for inclusion in Section 6.9, Addition of Proposed Generation to the Planning Models, to the Regional Transmission Plan base cases.

(3) ERCOT shall update the Regional Transmission Plan reliability and economic base cases to reflect any updates to the amount of Switchable Generation Resource (SWGR) capacity available to the ERCOT Region.

(4) ERCOT may, in its discretion, set a Generation Resource to out of service in the Regional Transmission Plan base cases prior to receiving a Notification of Suspension of Operations (NSO) if the Resource Entity notifies ERCOT of its intent to retire/mothball the Generation Resource and/or makes a public statement of its intent to retire/mothball the Generation Resource. ERCOT must provide reasonable advance notice to the RPG of any proposed Generation Resource retirements/mothballs and allow an opportunity for stakeholder comments.

(a) ERCOT will post and maintain the current list of Generation Resources that will be set to out of service pursuant to paragraph (4) above on the ERCOT website.

(5) In its Regional Transmission Plan studies, ERCOT shall first consider transmission needs without Remedial Action Scheme (RAS) or Constraint Management Plan (CMP) actions. After evaluating these needs, ERCOT may model a RAS or CMP in the Regional Transmission Plan cases only if ERCOT's initial studies did not identify a transmission project to exit the RAS or CMP, or if a transmission project to exit the RAS or CMP is not expected to be in service by the season and year the case represents.

(6) ERCOT may, in its discretion, make other adjustments to any Regional Transmission Plan base case to ensure that the case reaches a solution. ERCOT must provide reasonable advance notice to the RPG of any proposed adjustments and an opportunity for stakeholder comment on them.

4.1.1.2 Reliability Performance Criteria

Commented [EWG1]: Please note PGRR115 also proposes revisions to this section.

(1) The following reliability performance criteria (summarized in Table 1, ERCOT-specific Reliability Performance Criteria, below) shall be applicable to planning analyses in the ERCOT Region:

(a) With all Facilities in their normal state, following a common tower outage with or without a single line-to-ground fault, all Facilities shall be within their applicable Ratings, the ERCOT System shall remain stable with no cascading or uncontrolled Islanding, and there shall be no non-consequential Load loss;

(b) With all Facilities in their normal state, following an outage of a Direct Current Tie (DC Tie) Resource or DC Tie Load with or without a single line-to-ground fault, all Facilities shall be within their applicable Ratings, the ERCOT System shall remain stable with no cascading or uncontrolled Islanding, and there shall be no non-consequential Load loss;

(c) With any single generating unit unavailable, followed by Manual System Adjustments, followed by a common tower outage or outage of a DC Tie Resource or DC Tie Load with or without a single line-to-ground fault, all Facilities shall be within their applicable Ratings, the ERCOT System shall remain stable with no cascading or uncontrolled Islanding, and there shall be no non-consequential Load loss;

(d) With any single transformer, with the high voltage winding operated at 300 kV or above and low voltage winding operated at 100 kV or above unavailable, followed by Manual System Adjustments, followed by a common tower outage, or the contingency loss of a single generating unit, transmission circuit, transformer, shunt device, FACTS device, or DC Tie Resource or DC Tie Load with or without a single line-to-ground fault, all Facilities shall be within their applicable Ratings, the ERCOT System shall remain stable with no cascading or uncontrolled Islanding, and there shall be no non-consequential Load loss. An operational solution may be planned on a permanent basis to resolve a performance deficiency under this condition; and

(e) With any single DC Tie Resource or DC Tie Load unavailable, followed by Manual System Adjustments, followed by a common tower outage, or the contingency loss of a single generating unit, transmission circuit, transformer, shunt device, FACTS device, or DC Tie Resource or DC Tie Load, with or without a single line-to-ground fault, all Facilities shall be within their applicable Ratings, the ERCOT System shall remain stable with no cascading or uncontrolled Islanding, and there shall be no non-consequential Load loss. An operational solution may be planned on a permanent basis to resolve a performance deficiency under this condition.

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Initial Condition		Event	Facilities within Applicable Ratings and System Stable with No Cascading or Uncontrolled Outages	Non-consequential Load Loss Allowed
1	Normal System	Common tower outage, DC Tie Resource outage, or DC Tie Load outage	Yes	No
2	Unavailability of a generating unit, followed by Manual System Adjustments	Common tower outage, DC Tie Resource outage, or DC Tie Load outage	Yes	No
3	Unavailability of a transformer with the high voltage winding operated at 300 kV or above and low voltage winding operated at 100 kV or above, followed by Manual System Adjustments	Common tower outage; or Contingency loss of one of the following: 1. Generating unit; 2. Transmission circuit; 3. Transformer; 4. Shunt device; 5. FACTS device; or 6. DC Tie Resource or DC Tie Load	Yes	No

	Initial Condition	Event	Facilities within Applicable Ratings and System Stable with No Cascading or Uncontrolled Outages	Non-consequential Load Loss Allowed
4	Unavailability of a DC Tie Resource or DC Tie Load, followed by Manual System Adjustments	Common tower outage; or Contingency loss of one of the following: 1. Generating unit; 2. Transmission circuit; 3. Transformer; 4. Shunt device; 5. FACTS device; or 6. DC Tie Resource or DC Tie Load	Yes	No

Table 1: ERCOT-specific Reliability Performance Criteria

(2) ERCOT and the TSPs shall endeavor to resolve any performance deficiencies as appropriate. If a Transmission Facility improvement is required to meet the criteria in this Section 4.1.1.2, but the improvement cannot be implemented in time to resolve the performance deficiency, an interim solution may be used to resolve the deficiency until the improvement has been implemented.

(a) A Remedial Action Scheme (RAS) or Constraint Management Plan (CMP) shall not be planned to resolve a planning criteria performance deficiency unless it is expected that system conditions will change such that the RAS or CMP will no longer be needed within the next five years.

Revised ERCOT Impact Analysis Report

PGRR Number	113	PGRR Title	Related to NPRR1198, Congestion Mitigation Using Topology Reconfigurations
Impact Analysis Date	April 30, 2024		
Estimated Cost/Budgetary Impact	None.		
Estimated Time Requirements	No project required. This Planning Guide Revision Request (PGRR) can take effect upon implementation of Nodal Protocol Revision Request (NPRR) 1198, Congestion Mitigation Using Topology Reconfigurations.		
ERCOT Staffing Impacts (across all areas)	Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	No impacts to ERCOT computer systems.		
ERCOT Business Function Impacts	No impacts to ERCOT business functions.		
Grid Operations & Practices Impacts	No impacts to ERCOT grid operations and practices.		

Evaluation of Interim Solutions or Alternatives for a More Efficient Implementation
None offered.

Comments
There are no additional impacts to this PGRR beyond what was captured in the Impact Analysis for NPRR1198.

Board Report

PGRR Number	114	PGRR Title	Related to NPRR1212, Clarification of Distribution Service Provider's Obligation to Provide an ESI ID
Date of Decision		June 18, 2024	
Action		Recommended Approval	
Timeline		Normal	
Estimated Impacts		Cost/Budgetary: None Project Duration: No project required	
Proposed Effective Date		Upon implementation of Nodal Protocol Revision Request (NPRR) 1212, Clarification of Distribution Service Provider's Obligation to Provide an ESI ID	
Priority and Rank Assigned		Not applicable	
Planning Guide Sections Requiring Revision		5.5, Generator Commissioning and Continuing Operations	
Related Documents Requiring Revision/Related Revision Requests		NPRR1212	
Revision Description		This Planning Guide Revision Request (PGRR) modifies Section 5.5 to clarify that, before ERCOT approves Initial Energization for a project that will consume Load other than Wholesale Storage Load (WSL) and that is not behind a Non-Opt-In Entity (NOIE) tie meter, the Distribution Service Provider (DSP) must provide ERCOT with Electric Service Identifier(s) (ESI ID(s)) for the project and these ESI ID(s) must be established in the ERCOT Settlement system in a state that allows for the Load to be properly settled to the appropriate Qualified Scheduling Entity (QSE).	
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	Some Resources have gone through the Resource integration process without ERCOT receiving ESI ID(s) before they began consuming electricity. In the past, ERCOT has attributed that energy to Unaccounted for Energy (UFE) and has addressed this in the Final or True-Up Settlement at a later date. However, after 180 days, this cannot be remedied through the True-Up process. ERCOT needs to receive ESI ID(s) earlier in the Resource integration process to avoid the accrual of UFE that cannot be easily resettled. ERCOT has determined that clarification of the Protocols and the Planning Guide is needed to ensure that ERCOT timely receives ESI ID(s) before Initial Energization of a project at a Resource site. Ensuring that ESI ID(s) are provided before Initial Energization will avoid the creation of UFE for Initial Settlement.
ROS Decision	On 12/7/23, ROS voted unanimously to table PGRR114. All Market Segments participated in the vote. On 3/7/24, ROS voted to recommend approval of PGRR114 as amended by the 2/22/24 Oncor comments. There was one abstention from the Independent Retail Electric Provider (IREP) (Reliant) Market Segment. All Market Segments participated in the vote. On 4/4/24, ROS voted unanimously to endorse and forward to TAC the 3/7/24 ROS Report and the 11/22/23 Impact Analysis for PGRR114. All Market Segments participated in the vote.
Summary of ROS Discussion	On 12/7/23, ERCOT Staff reviewed PGRR114. Participants expressed a desire for Resource Integration Working Group (RIWG) review and tabled PGRR114 in anticipation of NPRR1212 discussion at the December 15, 2023 PRS meeting. On 3/7/24, ROS reviewed the 2/22/24 Oncor comments and referenced the NPRR1212 2/22/24 Oncor comments. On 4/4/24, ROS reviewed the 11/22/23 Impact Analysis and 4/3/24

	RMS comments.
TAC Decision	On 4/15/24, TAC voted to recommend approval of PGRR114 as recommended by ROS in the 4/4/24 ROS Report. There were four abstentions from the Cooperative (GSEC, LCRA, PEC, STEC) Market Segment. All Market Segments participated in the vote.
Summary of TAC Discussion	On 4/15/24, there was no discussion.
TAC Review/Justification of Recommendation	[X] Revision Request ties to Reason for Revision as explained in Justification [X] Impact Analysis reviewed and impacts are justified as explained in Justification [X] Opinions were reviewed and discussed [X] Comments were reviewed and discussed (if applicable) [ ] Other: (explain)
ERCOT Board Decision	On 6/18/24, the ERCOT Board voted unanimously to recommend approval of PGRR114 as recommended by TAC in the 4/15/24 TAC Report.

Opinions	
Credit Review	Not applicable
Independent Market Monitor Opinion	IMM has no opinion on PGRR114.
ERCOT Opinion	ERCOT supports approval of PGRR114.
ERCOT Market Impact Statement	ERCOT Staff has reviewed PGRR114 and believes that it provides a positive market impact by offering regulatory requirements which clarify that, before ERCOT approves Initial Energization for a project that will consume Load other than WSL and that is not behind a NOIE tie meter, the DSP must provide ERCOT with ESI ID(s) for the project, and that these ESI ID(s) must be established in the ERCOT Settlement system in a state that allows for the Load to be properly settled to the appropriate QSE.

Sponsor

Board Report

Name	Randy Roberts / Jay Teixeira / Douglas Fohn / Holly Heinrich
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Cell Number	
Market Segment	Not Applicable

Market Rules Staff Contact	
Name	Jordan Troublefield
E-Mail Address	Jordan.Troublefield@ercot.com
Phone Number	512-248-6521

Comments Received	
Comment Author	**Comment Summary**
Oncor 022224	Described Resource Entity's responsibility to request an ESI ID from its DSP and provide it to ERCOT, in concert with the NPRR1212 2/22/24 Oncor comments
RMS 040324	Endorsed PGRR114 as recommended by ROS in the 3/7/24 ROS Report

Market Rules Notes

Administrative changes to the language were made and authored as "ERCOT Market Rules."

Please note the baseline Planning Guide language in the following sections(s) has been updated to reflect the incorporation of the following PGRR(s) into the Planning Guide:

- PGRR109, Dynamic Model Review Process Improvement for Inverter-Based Resource (IBR) Modification (incorporated 5/1/24)
    - Section 5.5

Proposed Guide Language Revision

5.5 Generator Commissioning and Continuing Operations

(1) For each interconnecting Generation Resource or Energy Storage Resource (ESR), each Interconnecting Entity (IE) shall meet the conditions established by ERCOT before proceeding to Initial Energization, Initial Synchronization, and commercial operations. These conditions may require proof of meeting applicable ERCOT requirements, which may include, but are not limited to, reactive capability, voltage ride-through standards, dynamic model template submission, Automatic Voltage Regulator (AVR), Primary Frequency Response, Power System Stabilizer (PSS), Subsynchronous Resonance (SSR) models, and telemetry.

(2) Before ERCOT approves Initial Energization for a project that will consume Load other than Wholesale Storage Load (WSL) and that is not behind a Non-Opt-In Entity (NOIE) tie meter:

(a) ~~, the~~ The Resource Entity must request an Electric Service Identifier(s) (ESI ID(s)) from the Distribution Service Provider(s) (DSP(s)) that will be serving the Load at the Resource site and provide the ESI ID(s) to ERCOT, as described in paragraph (2) of Protocol Section 10.3.2, ERCOT-Polled Settlement Meters; and ~~Distribution Service Provider (DSP) must provide ERCOT with Electric Service Identifier(s) (ESI ID(s)) for the project.~~

(b) These ESI ID(s) must be established in the ERCOT Settlement system in a state that allows for the Load to be properly settled to the appropriate Qualified Scheduling Entity (QSE).

(3~~2~~) Within 300 days of receiving ERCOT's approval for Initial Synchronization above 20 MVA of a new or repowered Generation Resource or ESR, a Resource Entity shall ensure the Resource meets the conditions established by ERCOT for commercial operations and shall submit a request to ERCOT to commission the Resource.

(a) In the event a Generation Resource or ESR will be unable to complete all necessary construction and required testing to commence commercial operations and connect reliably to the ERCOT System within the 300 days, the Generation Resource or ESR may request a good cause exception with sufficient detail, and shall notify ERCOT prior to the planned commercial operation date and provide ERCOT with an updated commercial operation date that the Generation Resource or ESR can reasonably expect to commence operations in a reliable manner.

(~~3~~4) Prior to the Resource Commissioning Date of an Inverter-Based Resource (IBR), the IE associated with the IBR shall submit the appropriate dynamic models for the "as-built" data and the data submitted for the quarterly stability assessment, documentation clearly indicating any differences, results of the model quality tests of the "as-built" data overlaid with the results of the data submitted for the quarterly stability assessment, and associated simulation files pursuant to paragraph (5)(c) of Section 6.2, Dynamics Model Development. Submissions shall be sent electronically to Dynamicmodels@ercot.com for ERCOT review, and the phrase "IBR prior to commissioning" must be included in the subject line of the submission email. ERCOT shall respond to the IE within ten Business Days of the submission, indicating whether the submission is acceptable or if additional information is required. If additional time is needed for review, ERCOT can extend this review period by an additional 20 Business Days, and an email will be sent to notify the IE that it needs additional time to review the submission. The time for ERCOT to review models and associated documentation will be a qualified cause to extend the allowed time to complete the conditions established by ERCOT for commercial operations.

(45~~3~~) No later than 30 days following the Resource Commissioning Date, the Resource Entity shall submit updates to the resource dynamic planning and operations models through the online Resource Integration and Ongoing Operations (RIOO) system based on "as-built" data and provide a plant verification report as required by paragraph (5)(b) of Section 6.2. Pursuant to paragraph (5)(c) of Section 6.2, the Resource Entity shall include model updates with model quality tests.

(~~5~~64) During continuing operations:

(a) Prior to the implementation of modification to any control settings or equipment of an IBR that impacts the dynamic response (such as voltage, frequency, and current injections) at the Point of Interconnection (POI), the proposed modification shall be reviewed by the interconnecting Transmission Service Provider (TSP) and ERCOT:

(i) The Resource Entity shall submit the appropriate dynamic model for the proposed modification, results of the model quality tests overlaid with the results before the modification, and associated simulation files pursuant to paragraph (5)(c) of Section 6.2. Submissions shall be sent electronically to Dynamicmodels@ercot.com for ERCOT review, and the phrase "IBR proposed modification" must be included in the subject line of the submission email. The Resource Entity may withdraw its modification plan at any time during the review process if the Resource Entity no longer wishes to proceed with the modification.

(ii) ERCOT shall respond to the Resource Entity within ten Business Days of the submission in paragraph (i) above, indicating whether the submission is acceptable or if additional information is required. ERCOT can extend this review period by an additional 20 Business Days, and an email will be sent to notify the Resource Entity that it needs additional time to review the submission.

(iii) Upon completing its review of the model quality tests, ERCOT shall notify the Resource Entity and the interconnecting TSP of its determination. The notification will indicate one of the following:

(A) ERCOT recommends that the interconnecting TSP conduct a limited dynamic stability study comparing electrical performance before and after the proposed modification, and reasonably evaluate whether the proposed modification may present dynamic stability risks that should be subject to further study.

(B) The proposed modification is applicable to paragraph (1)(c)(iii) of Section 5.2.1, Applicability. The Resource Entity shall initiate a Generator Interconnection or Modification (GIM) request through RIOO.

(C) The proposed modification is deemed unacceptable.

(D) The proposed modification is deemed acceptable without need for a dynamic stability study.

(iv) Within 90 days of the receipt of the accepted submission in paragraph (iii)(A) above, the interconnecting TSP shall submit its dynamic stability study report to ERCOT electronically to Dynamicmodels@ercot.com.

(v) ERCOT shall review the dynamic stability study report submitted by the interconnecting TSP within ten Business Days. ERCOT can extend this review period by an additional 20 Business Days, and an email will be sent to notify the interconnecting TSP and the Resource Entity that it needs additional time to review the dynamic stability study report.

(vi) Upon completing its review and ERCOT acceptance of the dynamic stability study report, ERCOT shall notify the Resource Entity and the interconnecting TSP of its determination. The notification will indicate one of the following:

(A) The proposed modification is deemed acceptable.

(B) The proposed modification is applicable to paragraph (1)(c) of Section 5.2.1. The Resource Entity shall initiate a GIM request through RIOO.

(vii) ERCOT, in consultation with the interconnecting TSP, may allow the proposed changes to be temporarily implemented prior to the above review process in order to address any identified performance deficiency.

(b) Pursuant to paragraph (5)(c) of Section 6.2, the Resource Entity shall include model updates with model quality tests.

(c) The Resource Entity shall provide ERCOT with a plant verification report as required by paragraph (5)(b) of Section 6.2 at the following times:

(i) No later than 30 days after implementing a settings change as required by paragraph (7) of Section 6.2;

(ii) No earlier than 12 months and no later than 24 months following the later of the Resource Commissioning Date or March 1, 2021; and

(iii) A minimum of every ten years.

ERCOT Impact Analysis Report

PGRR Number	114	**PGRR Title**	**Related to NPRR1212, Clarification of Distribution Service Provider's Obligation to Provide an ESI ID**
Impact Analysis Date	November 22, 2023		
Estimated Cost/Budgetary Impact	None.		
Estimated Time Requirements	No project required. This Profiling Guide Revision Request (PGRR) can take effect upon implementation of Nodal Protocol Revision Request (NPRR) 1212, Clarification of Distribution Service Provider's Obligation to Provide an ESI ID.		
ERCOT Staffing Impacts (across all areas)	Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	No impacts to ERCOT computer systems.		
ERCOT Business Function Impacts	No impacts to ERCOT business functions.		
Grid Operations & Practices Impacts	No impacts to ERCOT grid operations and practices.		

Evaluation of Interim Solutions or Alternatives for a More Efficient Implementation
None offered.

Comments
None.