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| NOGRR Number | [258](https://www.ercot.com/mktrules/issues/NOGRR258) | NOGRR Title | Related to NPRR1198, Congestion Mitigation Using Topology Reconfigurations |
| Date of Decision | | May 2, 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](https://www.ercot.com/files/docs/2023/08/25/ERCOT-Strategic-Plan-2024-2028.pdf) Objective 1 – Be an industry leader for grid reliability and resilience  [Strategic Plan](https://www.ercot.com/files/docs/2023/08/25/ERCOT-Strategic-Plan-2024-2028.pdf) Objective 2 - Enhance the ERCOT region’s economic competitiveness with respect to trends in wholesale power rates and retail electricity prices to consumers  [Strategic Plan](https://www.ercot.com/files/docs/2023/08/25/ERCOT-Strategic-Plan-2024-2028.pdf) Objective 3 - Advance ERCOT, Inc. as an independent leading industry expert and an employer of choice by fostering innovation, investing in our people, and emphasizing the importance of our mission  General system and/or process improvement(s)  Regulatory requirements  ERCOT Board/PUCT Directive  *(please select ONLY ONE – if more than one apply, please select the ONE that is most relevant)* | |
| Justification of Reason for Revision and Market Impacts | | 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. | |
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| **Opinions** | | | |
| Credit Review | | Not applicable | |
| Independent Market Monitor Opinion | | To be determined | |
| ERCOT Opinion | | To be determined | |
| ERCOT Market Impact Statement | | To be determined | |

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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 |
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| **Market Rules Notes** | |

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

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| 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);

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

(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.

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| ***[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) 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.

(4) 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.

(5) ERCOT is not required to provide notification to the market of any proposed TOAPs.

(6) All submittals related to CMPs or RASs must be emailed to [ras\_cmp@ercot.com](mailto: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 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) 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) 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) 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 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 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 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 proposed RAP is approved, 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 (4) of Section 11.1, Introduction.

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

**11.8 Extended Action Plans (EAPs)**

(1) Extended Action Plans (EAPs) must be approved prior to implementation by ERCOT, the Transmission Operators (TOs) that operate the affected equipment, and Resource Entities that are directly impacted operationally. 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 by the Resource Entities and TOs that are directly impacted operationally by the EAP;

(b) Be restored to normal configuration when either:

1. 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
2. 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.

(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 for economic reasons on the ERCOT Transmission Grid, ERCOT must verify that the EAP:

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

(b) Does not result in radial Load ;

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

(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 115 kV and above;

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

(f) Provides more than $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) Limits the action to changing the normal status of circuit breakers at up to three substations;

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

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

(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 by the TO in coordination with ERCOT, on the effective date of the EAP.

(4) All proposed, approved, amended, and removed EAPs shall be managed in accordance with paragraph (4) 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 by the TO or by ERCOT for reliability reasons, or for the duration of a Transmission Facility 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 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):

(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 days of receipt, and may request additional time if necessary while making reasonable efforts to consider proposed EAPs as soon as possible;

(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) EAPs submitted by a Market Participant will be posted on the Market Information System (MIS) Secure Area by ERCOT within five Business Days of receipt of a complete submission.

(c) ERCOT will provide a 30 day comment period from the date the proposed EAP is posted to the MIS Secure Area by ERCOT, unless notice of a shorter comment period is provided by ERCOT.

(d) ERCOT shall consider all comments received within the 30 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) When 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.

1. 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.
2. 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.