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| NPRR Number | [1198](https://www.ercot.com/mktrules/issues/NPRR1198) | NPRR Title | Congestion Mitigation Using Topology Reconfigurations |
| Date of Decision | | May 9, 2024 | |
| **Action** | | Recommended Approval | |
| Timeline | | Normal | |
| Estimated Impacts | | Cost/Budgetary: Between $50k and $80k; Between $180k and $220k (Annual Recurring O&M)  Project Duration: 4 to 7 months | |
| Proposed Effective Date | | Upon system implementation | |
| Priority and Rank Assigned | | Priority – 2025; Rank – 4520 | |
| Nodal Protocol Sections Requiring Revision | | 2.1, Definitions  3.10.7.4, Remedial Action Schemes, Automatic Mitigation Plans and Remedial Action Plans  6.5.1.1, ERCOT Control Area Authority | |
| Related Documents Requiring Revision/Related Revision Requests | | Nodal Operating Guide Revision Request (NOGRR) 258, Related to NPRR1198, Congestion Mitigation Using Topology Reconfigurations  Planning Guide Revision Request (PGRR) 113, Related to NPRR1198, Congestion Mitigation Using Topology Reconfigurations | |
| Revision Description | | This Nodal Protocol Revision Request (NPRR) defines Extended Action Plan (EAP), adds EAP as a type of Constraint Management Plan (CMP) suitable for managing congestion that is resolvable by Security-Constrained Economic Dispatch (SCED), and removes language limiting the application of EAPs to congestion issues for which there exists no feasible SCED.  The related NOGRR258 proposes changes that add language to allow the use of EAPs to address congestion that is resolvable by SCED, 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 NPRR and NOGRR258 leverage ERCOT’s existing 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, Constraint Management Plan, was introduced in 2013 with the limitations that this NPRR 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 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 NPRR 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 NPRR and NOGRR258 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. | |
| PRS Decision | | On 10/12/23, PRS voted unanimously to table NPRR1198 and refer the issue to ROS and WMS. All Market Segments participated in the vote.  On 4/5/24, PRS voted to recommend approval of NPRR1198 as amended by the 3/8/24 LCRA comments. There were four abstentions from the Cooperative (STEC), Independent Generator (2) (Jupiter Power, Calpine), and Investor Owned Utility (IOU) (CNP) Market Segments. All Market Segments participated in the vote.  On 5/9/24, PRS voted to endorse and forward to TAC the 4/5/24 PRS Report and 4/30/24 Impact Analysis for NPRR1198 with a recommended priority of 2025 and rank of 4520. There were three abstentions from the Cooperative (STEC), Independent Generator (Calpine), and IOU (CNP) Market Segments. All Market Segments participated in the vote. | |
| Summary of PRS Discussion | | On 10/12/23, participants discussed referring the issue to ROS and WMS, and requested leadership provide guidance on the scope of discussions at the subcommittees.  On 4/5/24, participants reviewed the 3/8/24 LCRA comments.  On 5/9/24, participants reviewed the 4/30/24 Impact Analysis. | |
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| **Opinions** | | | |
| Credit Review | | ERCOT Credit Staff and the Credit Finance Sub Group (CFSG) have reviewed NPRR1198 and do not believe that it requires changes to credit monitoring activity or the calculation of liability. | |
| Independent Market Monitor Opinion | | To be determined | |
| ERCOT Opinion | | ERCOT supports approval of NPRR1198. | |
| ERCOT Market Impact Statement | | ERCOT Staff has reviewed NPRR 1198 and believes that it provides a positive market impact by leveraging ERCOT’s existing CMP process to mitigate critical transmission congestion impacts. | |

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| Sponsor | |
| Name | Alexandra Miller |
| E-mail Address | [Alexandra.Miller@edf-re.com](mailto:Alexandra.Miller@edf-re.com) |
| Company | EDF Renewables, Inc. |
| Phone Number | 858-946-3245 |
| Cell Number | 615-420-0471 |
| Market Segment | Independent Generator |

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| **Market Rules Staff Contact** | |
| **Name** | Erin Wasik-Gutierrez |
| **E-Mail Address** | [erin.wasik-gutierrez@ercot.com](mailto:erin.wasik-gutierrez@ercot.com) |
| **Phone Number** | 413-886-2474 |
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| **Comments Received** | |
| **Comment Author** | **Comment Summary** |
| IMM 090623 | Supported concept and encouraged approval of NPRR1198 |
| Octopus Energy 092023 | Supported NPRR1198 |
| Engie 100423 | Supported NPRR1198 |
| EDF Renewables 103023 | Integrated feedback received during stakeholder meeting discussions |
| WMS 110123 | Requested PRS to continue to table NPRR1198 for further review by the Congestion Management Working Group (CMWG) |
| ROS 110323 | Requested PRS to continue to table NPRR1198 for further review by the Operations Working Group (OWG) |
| Oncor 012224 | Revised language to limit the scope of NPRR1198 to EAPs; modified the EAP definition to specify they are intended to address significant congestion; included the role of Outage Scheduling in the EAP management process |
| LCRA 030824 | Modified the EAP definition to clarify it can be submitted for reliability and economic reasons |
| WMS 040424 | Endorsed NPRR1198 as amended by the 3/8/24 LCRA comments |
| ROS 040424 | Endorsed NPRR1198 as amended by the 3/8/24 LCRA comments |

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| **Market Rules Notes** |

None

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| Proposed Protocol Language Revision |

## 2.1 DEFINITIONS

**Constraint Management Plan (CMP)**

A set of pre-defined manual transmission system actions, or automatic transmission system actions that do not constitute a Remedial Action Scheme (RAS), which are executed in response to system conditions to prevent or to resolve one or more thermal or non-thermal transmission security violations or to optimize the transmission system. ERCOT will employ CMPs to maintain system security and reliability in accordance with the Protocols, Nodal Operating Guides and North American Electric Reliability Corporation (NERC) Reliability Standards. .

CMPs include, but are not limited to the following:

***Automatic Mitigation Plan (AMP)***

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

***Extended Action Plan (EAP)***

A set of pre-defined manual actions to execute pre-contingency and to remain in place for a pre-defined period of time to address voltage issues or reduce overloading on one or more given monitored Transmission Facilities to below their Emergency Rating with restoration of normal operating conditions within two hours. 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 and meet the criteria outlined in Nodal Operating Guide Section 11, Constraint Management Plans and Remedial Action Schemes. An EAP may include transmission switching and does not include Load shedding. EAPs shall be managed via the Network Operations Model Change Request (NOMCR) and Outage scheduling processes as described in Nodal Operating Guide Section 11.8.1, Extended Action Plan (EAP) Process.

***Mitigation Plan***

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

***Pre-Contingency Action Plan (PCAP)***

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

***Remedial Action Plan (RAP)***

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

***Temporary Outage Action Plan (TOAP)***

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

3.10.7.4 Remedial Action Schemes, Automatic Mitigation Plans, Extended Action Plans and Remedial Action Plans

(1) All approved Remedial Action Schemes (RASs), Automatic Mitigation Plans (AMPs), Extended Action Plans (EAPs) and Remedial Action Plans (RAPs) must be defined in the Network Operations Model where practicable.

(2) Proposed new RASs, AMPs, EAPs and RAPs and proposed changes to RASs, AMPs, EAPs and RAPs must be submitted to ERCOT for review and approval. ERCOT shall seek input from TSPs and Resource Entities that own Transmission Facilities included in the RASs, AMPs, EAPs or RAPs, and shall approve proposed new RASs, AMPs, EAPs and RAPs and proposed changes to RASs, AMPs, EAPs and RAPs in accordance with the process outlined in the Operating Guides. This shall include verification of the Network Operations Model. ERCOT shall provide notification to the market and post all RASs, AMPs, EAPs and RAPs under consideration on the MIS Secure Area within five Business Days of receipt.

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| ***[NPRR857: Replace paragraph (2) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (2) Proposed new RASs, AMPs, EAPs and RAPs and proposed changes to RASs, AMPs, EAPs and RAPs must be submitted to ERCOT for review and approval. ERCOT shall seek input from TSPs, DCTOs, and Resource Entities that own Transmission Facilities included in the RASs, AMPs, EAPs or RAPs, and shall approve proposed new RASs, AMPs, EAPs and RAPs and proposed changes to RASs, AMPs, EAPs and RAPs in accordance with the process outlined in the Operating Guides. This shall include verification of the Network Operations Model. ERCOT shall provide notification to the market and post all RASs, AMPs, EAPs and RAPs under consideration on the MIS Secure Area within five Business Days of receipt. |

(3) ERCOT shall use a NOMCR to model approved RASs, AMPs, EAPs and RAPs where practicable and include the RASs, AMPs, EAPs or RAPs modeled in the Network Operations Model in the security analysis. The NOMCR shall include a detailed description of the system conditions required to implement the RASs, AMPs, EAPs or RAPs. If an approved RAS, AMP, or RAP cannot be modeled, then ERCOT shall develop an alternative method for recognizing the unmodeled RAS, AMP, or RAP in its tools. Execution of RASs, AMPs, EAPs or RAPs modeled in the Network Operations Model shall be included or assumed in the calculation of LMPs. ERCOT shall provide notification to the market and post on the MIS Secure Area all approved RASs, AMPs, EAPs and RAPs at least two Business Days before implementation, identifying the date of implementation. The notification to the market shall state whether the approved RAP, AMP, EAP or RAS will be modeled in the Network Operations Model. For RAPs developed in Real-Time, ERCOT shall provide notification to the market as soon as practicable.

**6.5.1.1 ERCOT Control Area Authority**

(1) ERCOT, as Control Area Operator (CAO), is authorized to perform the following actions for the limited purpose of securely operating the ERCOT Transmission Grid under the standards specified in North American Electric Reliability Corporation (NERC) Standards, the Nodal Operating Guides and these Protocols,including:

(a) Direct the physical operation of the ERCOT Transmission Grid, including circuit breakers, switches, voltage control equipment, and Load-shedding equipment;

(b) Dispatch Resources that have committed to provide Ancillary Services;

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| ***[NPRR1010: Replace paragraph (b) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (b) Dispatch Resources that have been awarded Ancillary Services; |

(c) Direct changes in the operation of voltage control equipment;

(d) Direct the implementation of Reliability Must-Run (RMR) Service;

(e) Direct the implementation, disabling, or reversal of implementation of Remedial Action Plans (RAPs), Automatic Mitigation Plans (AMPs), Remedial Action Schemes (RASs), Pre-Contingency Action Plans (PCAPs), Extended Action Plans (EAPs), and transmission switching to prevent the violation of ERCOT Transmission Grid security limits; and

(f) Perform additional actions required to prevent an imminent Emergency Condition or to restore the ERCOT Transmission Grid to a secure state in the event of an ERCOT Transmission Grid Emergency Condition.

(2) Unless the ERCOT Protocols or Other Binding Documents explicitly provide otherwise, ERCOT shall not model, monitor, direct operation of, or otherwise exercise any operational authority over any facility that operates on the low voltage side of the distribution transformer except as may be necessary for the following purposes:

(a) To ensure the reliable interconnection, dispatch, operation, and Settlement of any Generation Resource, Energy Storage Resource (ESR), Load Resource, or Emergency Response Service (ERS) Resource that is, or is proposed to be, interconnected at distribution voltage, and to ensure the reliable operation and Settlement of any other ERCOT-registered generator or Energy Storage System (ESS);

(b) To provide ERCOT information about all generators and ESS interconnected at distribution voltage as requested by ERCOT pursuant to these Protocols or Other Binding Documents for the purposes of ensuring accurate Settlement and operating and planning the ERCOT Transmission Grid; and

(c) To effectuate automatic or manual Load shedding as prescribed by these Protocols or Other Binding Documents.

(3) Nothing in paragraph (2) above limits ERCOT’s authority to require that a Transmission Service Provider (TSP) or Transmission Operator (TO) disconnect any Facility operated at distribution voltage from the ERCOT System if ERCOT determines such action is necessary to address a reliability concern on the ERCOT Transmission Grid. Additionally, nothing in paragraph (2) above limits ERCOT’s authority to require appropriate modeling and telemetry of transmission Loads that may represent multiple distribution-level Loads, as provided in Section 3.10.7.2, Modeling of Resources and Transmission Loads.

(4) Consistent with paragraph (1)(f) above, if ERCOT seeks to exercise its authority to prevent an anticipated Emergency Condition relating to serving Load in the current or next Season by procuring existing capacity that may be used to maintain ERCOT System reliability in a manner not otherwise delineated in these Protocols and the Nodal Operating Guides, ERCOT shall take the following actions:

(a) Upon determination by ERCOT that additional capacity is needed to prevent an Emergency Condition and prior to any procurement activity associated with such additional capacity, ERCOT shall issue a Notice as soon as practicable with the following information:

(i) A detailed description of the reliability condition and need for additional capacity as determined by ERCOT and the timing of the proposed procurement;

(ii) Justification for the quantity of additional capacity to be requested;

(iii) Identification of potential Generation Resources or Load providing capacity considered by ERCOT to be acceptable for providing the additional capacity. Load capacity may be provided by Entities who, at ERCOT’s direction, would interrupt consumption of electric power and remain interrupted until released by ERCOT; and

(iv) A schedule of activities associated with the proposed procurement.

(b) If ERCOT identifies a specific Entity with which it will negotiate the terms for procurement of additional capacity, then ERCOT shall issue a Notice as soon as practicable that includes the Entity name and, as applicable, the Resource mnemonic, the Resource MW rating by Season, the name of the Resource Entity, and the potential duration of any contract, including anticipated start and end dates.

(c) ERCOT shall, to the fullest extent practicable, ensure that any actions taken to procure additional capacity meet the following criteria:

(i) Any capacity procured pursuant to this paragraph will be procured using an open process, and the terms of the procurement between ERCOT and the Entity will be memorialized in contracts that will be publicly available for inspection on the ERCOT website.

(ii) Each contract will include specified financial terms and termination dates. For purposes of Settlement, any contract associated with a Generation Resource will include substantially the same terms and conditions as an RMR Unit under a RMR Agreement, including the Eligible Cost budgeting process.

(iii) ERCOT shall provide notice to the ERCOT Board, at the next ERCOT Board meeting after ERCOT has signed the contract, that the actions required prior to execution of the contract, pursuant to paragraphs (4)(a) through (c) above, were completed by ERCOT before the contract was executed.

(iv) Any information submitted by the Entity to ERCOT through the procurement process may be designated as Protected Information and treated in accordance with the provisions of Section 1.3, Confidentiality, provided that final contract terms must be made available for public inspection.

(d) A Generation Resource that has received capital contributions from ERCOT pursuant to a contract executed under this paragraph (4) may not participate in the energy or Ancillary Services markets until such capital contributions have been refunded to ERCOT. For the purposes of this Section, capital contributions are defined as improvements with an asset life greater than one year under the applicable federal tax rules. The Resource Entity’s refund of capital contributions shall be a lump sum payment calculated as follows:

(i) If the Generation Resource chooses to participate in the energy or Ancillary Service markets after the termination date of the contract executed under this paragraph (4), the Qualified Scheduling Entity (QSE) representing the Resource Entity shall repay, in a lump sum payment, 100% of the book value of the capitalized equipment and all installation charges leading to turn key, one-time startup based on a linear depreciation over the estimated life of the capitalized component(s) in accordance with Generally Accepted Accounting Principles (GAAP) standards for electric utility equipment. The estimated life shall be based on documentation provided by the manufacturer; if installing used equipment, the estimated life may be based on an approximation agreed to by the Resource Entity and ERCOT.

(ii) If the Generation Resource chooses to participate in the energy or Ancillary Services markets as contemplated in item (4)(d)(i) above, and its participation requires a lump sum payment of capital contributions, ERCOT will issue a notice to all registered Market Participants announcing the Generation Resource’s decision to participate in the market(s) and identifying the amount of the lump sum payment due pursuant to item (4)(d)(i) above. ERCOT will also issue a notice to all registered Market Participants after completion of the collection and disbursement of the capital contributions, as described in item (4)(d)(iii) below, and after resolution of any disputes related to these capital contributions.

(iii) After ERCOT receives a Notification of Change of Generation Resource Designation (Section 22, Attachment H, Notification of Change of Generation Resource Designation) changing the Resource designation to “operational” at a future date, ERCOT shall charge the QSE representing the Resource Entity for capital expenditures incurred and previously paid to the Resource Entity as a result of the Resource’s return to service pursuant to this Section.

(A) For months in the contract term where notice is received more than five Business Days prior to True-Up Settlement of the first Operating Day of that month, ERCOT shall claw back any payments made for the capital expenditure associated with that month and subsequent months of the term, on the next practical Settlement but no later than the True-Up Settlement.

(B) For months in the contract term where notice is received five Business Days or less prior to True-Up Settlement of the first Operating Day of that month, ERCOT shall claw back any payments made for the capital expenditures within 45 days of receipt of the notice.

(C) ERCOT shall distribute the repayment to QSEs representing Load on the same basis used to collect the monthly capital expenditures, using a monthly Load Ratio Share (LRS). A QSE’s monthly LRS shall be the QSE’s total Real-Time Adjusted Metered Load (AML) for the month divided by the total ERCOT Real-Time AML for the same month.

(e) ERCOT shall endeavor to minimize the deployment of capacity procured pursuant to this paragraph with the goal of reducing the potential distortion of markets. Resources and Loads deployed to alleviate imminent Emergency Conditions will not be offered into the Day-Ahead Market (DAM). Rather, ERCOT will determine whether to use the capacity as part of the Hourly Reliability Unit Commitment (HRUC) process based on system conditions and the ability to meet Demand. In the event Generation Resources are committed and On-Line, ERCOT systems will generate a proxy offer for the Generation Resource at the System-Wide Offer Cap (SWCAP). The default offer will place the Generation Resources among the last for economic Dispatch, so as not to displace Generation Resources that are On-Line and offering into the market. To the extent practicable, the capacity deployed to alleviate imminent Emergency Conditions will not be used solely for the purpose of reducing local congestion.

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| [NPRR1010: Replace paragraph (e) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]  (e) ERCOT shall endeavor to minimize the deployment of capacity procured pursuant to this paragraph with the goal of reducing the potential distortion of markets. Resources and Loads deployed to alleviate imminent Emergency Conditions will not be offered into the Day-Ahead Market (DAM). Rather, ERCOT will determine whether to use the capacity as part of the Hourly Reliability Unit Commitment (HRUC) process based on system conditions and the ability to meet Demand. In the event Generation Resources are committed and On-Line, ERCOT systems will generate a proxy offer for the Generation Resource at the Real-Time System-Wide Offer Cap (RTSWCAP). The default offer will place the Generation Resources among the last for economic Dispatch, so as not to displace Generation Resources that are On-Line and offering into the market. To the extent practicable, the capacity deployed to alleviate imminent Emergency Conditions will not be used solely for the purpose of reducing local congestion. |

(f) An Entity cannot be compelled to enter into a contract under this paragraph.