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| NOGRR Number | [268](https://www.ercot.com/mktrules/issues/NOGRR268) | NOGRR Title | Related to NPRR1246, Energy Storage Resource Terminology Alignment for the Single-Model Era |

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| Date | January 21, 2025 |

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| Market Segment | Not applicable |

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| Comments |

ERCOT submits these comments to Nodal Operating Guide Revision Request (NOGRR) 268 to align with NOGRR262, Provisions for Operator-Controlled Manual Load Shed, which was approved by the Public Utility Commission of Texas (PUCT) on November 21, 2024.

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| Revised Cover Page Language |

None

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| Revised Proposed Guide Language |

1.4 Definitions

Automatic Generation Control (AGC)

Application that receives signals from ERCOT for Regulation deployment and causes Resources providing these Ancillary Services to respond in accordance with their ramp rate to meet the received deployments.

Generator Reactive Power Sign/Direction Terminology

(1) Lagging power factor operating condition is when MVAr flow is out of the Generation Resource (overexcited generator) or Energy Storage Resource (ESR). The generator is producing MVArs.

(2) Leading power factor operating condition is when MVAr flow is into the Generation Resource (underexcited generator) or ESR. The generator is absorbing MVArs.

***1.5.2 System Operator Training Requirements***

(1) The System Operator Training Program applies to all operators who are responsible for the Day-Ahead and Real-Time operation of the ERCOT Transmission Grid. Transmission Operators (TOs) and Qualified Scheduling Entity (QSE) operators who represent Generation Resources, Energy Storage Resources (ESRs), and Load Resources shall participate in 32 hours per year of training and drills on system emergencies. QSE operators who do not represent Generation Resources, ESRs, or Load Resources must participate in at least eight hours per year of training and drills in system emergencies.

(2) For those operators required to obtain 32 hours annually at least eight hours must be from simulations or realistic drills.

(3) Training should use simulations appropriate to each class of operator and all such training shall meet or exceed established NERC Reliability Standards.

(4) Participation in emergency simulations, severe weather drills, ERCOT Black Start training, and portions of the ERCOT Operations Training Seminar that relate to NERC recommended topics may be used to satisfy this requirement.

(5) ERCOT Black Start training attendance is mandatory for all TOs, QSEs identified in a Black Start restoration plan, Resource Entities that represent Black Start Resources, and other Entities who are notified by ERCOT that their participation is required.

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| ***[NOGRR194: Replace paragraph (5) above with the following upon system implementation of NPRR857:]***  (5) ERCOT Black Start training attendance is required for all TOs, Direct Current Tie Operators (DCTOs), QSEs identified in a Black Start restoration plan, Resource Entities that represent Black Start Resources, and other Entities who are notified by ERCOT that their participation is required. |

(6) Attendance at Black Start training is limited to those Entities identified in paragraph (5) above, ERCOT staff, Public Utility Commission of Texas (PUCT), Reliability Monitor, or other Entities deemed by ERCOT to have a legitimate reliability reason to attend.

(7) Task specific training carried out internally within an Entity will be considered in full compliance with this requirement. Training documentation, including curriculum, training methods, and individual training records, shall be immediately available during any audit.

***1.5.4 ERCOT Severe Weather Drill***

(1) An annual severe weather drill will be held to test the scheduling and communication functions of the primary and/or backup control centers and to train operators in emergency procedures. On an annual basis, ERCOT shall:

(a) Develop and coordinate, with assistance from the Operations Working Group (OWG), the severe weather drill;

(b) Conduct a severe weather drill; and

(c) Verify and report Entity participation in the severe weather drill to the OWG, the Reliability Monitor, and the NERC Regional Entity.

(2) TOs and QSEs that represent Generation Resources and/or ESRs are required to participate in the severe weather drill.

(3) On an annual basis, OWG shall:

(a) Review and critique the results of completed severe weather drills to ensure effectiveness and recommend changes as necessary to ERCOT; and

(b) Report results of the severe weather drill to the Reliability and Operations Subcommittee (ROS).

**2.1 Operational Duties**

(1) The duties of ERCOT are described in relevant sections of the Protocols and North American Electric Reliability Corporation (NERC) Reliability Standards. These Operating Guides assume that all actions taken will be on components of, or related to, the ERCOT System unless otherwise specified. The primary operational duties of ERCOT are to ensure the reliability of the ERCOT System. In doing this ERCOT shall:

(2) Perform operational planning:

(a) Perform the Reliability Unit Commitment (RUC) processes in order to commit additional resources as needed to maintain reliability;

(b) Perform operational ERCOT Transmission Grid reliability studies, including those related to generation and load interconnection responsibilities;

(c) Review all Outages of Generation Resources, Energy Storage Resources (ESRs), and major transmission lines or components to identify and correct possible failure to meet credible N-1 criteria. This shall include possible failure to meet N-1 criteria not resolved through the Day-Ahead process;

(d) Perform load flows and security analyses of Outages submitted by Qualified Scheduling Entities (QSEs) or Transmission Service Providers (TSPs) as a basis for approval or rejection as described in Protocol Section 3.1, Outage Coordination;

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| ***[NOGRR177: Replace paragraph (d) above with the following upon system implementation of NPRR857:]***  (d) Perform load flows and security analyses of Outages submitted by Qualified Scheduling Entities (QSEs), Transmission Service Providers (TSPs), or Direct Current Tie Operators (DCTOs) as a basis for approval or rejection as described in Protocol Section 3.1, Outage Coordination; |

(e) Withdraw approval of a scheduled Outage if unable to meet credible N-1 criteria after all other reasonable options are exercised as described in Protocol Section 3.1;

(f) Serve as the point of contact for initiation of generation interconnection to the ERCOT Transmission Grid;

(g) Forecast Load and Resources for the next seven days for reliability planning; and

(h) Ensure that sufficient Resources in the proper location and required Ancillary Services have been committed for all expected Load on a Day-Ahead and Real-Time basis.

(3) Operate energy and Ancillary Service markets:

(a) Administer a Congestion Revenue Rights (CRR) market;

(b) Administer a Day-Ahead Market (DAM) including both energy and Ancillary Service;

(c) Administer the RUC processes;

(d) If necessary, administer a Supplemental Ancillary Service Market (SASM); and

(e) Administer a Real-Time energy market using Security-Constrained Economic Dispatch (SCED).

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| ***[NOGRR211: Replace paragraph (3) above with the following upon system implementation of NPRR1007:]***  (3) Operate energy and Ancillary Service markets:  (a) Administer a Congestion Revenue Rights (CRR) market;  (b) Administer a Day-Ahead Market (DAM) including both energy and Ancillary Service;  (c) Administer the RUC processes; and  (d) Administer a Real-Time Market (RTM) including energy and Ancillary Services using Security-Constrained Economic Dispatch (SCED). |

(4) Supervise the ERCOT System to meet NERC Reliability Standards:

(a) Monitor and evaluate ERCOT System conditions on a continuous basis;

(b) Coordinate with Transmission Operators (TOs), ERCOT System events to maintain or restore reliability;

(c) Dispatch Generation Resources and ESRs via the SCED process and deployment of Ancillary Services to control frequency and congestion;

(d) Provide access to the ERCOT System on a nondiscriminatory basis;

(e) Approve schedules of interchange transactions across the Direct Current Ties (DC Ties); and

(f) Direct emergency operations.

(5) Collect and Disseminate Information:

(a) Collect, process, and disseminate market, operational and settlement information;

(b) Provide relevant operational information to Market Participants over the Market Information System (MIS);

(c) Collect and maintain operational data required by the Public Utility Commission of Texas (PUCT), NERC and Protocols;

(d) Receive reports from TOs and QSEs and forward them to the Department of Energy (DOE), NERC, and/or other Governmental Authority as required;

(e) Submit reports to DOE, NERC, and/or other Governmental Authority as required; and

(f) Record and report accumulated time error.

***2.2.3 Response to Transient Voltage Disturbance***

(1) Generation Resources and Energy Storage Resources (ESRs) should be designed in accordance with Section 6.2, System Protective Relaying, in order to properly respond to transient voltage disturbances.

***2.2.4 Load Frequency Control***

(1) ERCOT shall operate the Load Frequency Control (LFC) system to maintain the scheduled frequency at 60 Hz (correcting periodically for time error) and to minimize the use of energy from Resources providing Regulation Service.

(2) The ERCOT LFC system shall deploy Regulation Service energy, and release Responsive Reserve (RRS) and ERCOT Contingency Reserve Service (ECRS) capacity to Security-Constrained Economic Dispatch (SCED), as necessary, in accordance with Protocol Section 6.5.7.6, Load Frequency Control, to meet North American Electric Reliability Corporation (NERC) Reliability Standards. ERCOT shall purchase Regulation Service to provide satisfactory frequency control performance for the ERCOT Region. ERCOT shall determine the satisfactory amount of Regulation Service, required by statistical analysis of possible Resource Outages and Load forecast error, to expect operation of 95% of hours without deploying RRS.

(3) QSEs shall use Automatic Generation Control (AGC) to direct the output of Resources providing Regulation.

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| ***[NOGRR211: Replace Section 2.2.4 above with the following upon system implementation of NPRR1007:]***  ***2.2.4 Load Frequency Control***  (1) ERCOT shall operate the Load Frequency Control (LFC) system to maintain the scheduled frequency at 60 Hz (correcting periodically for time error) and to minimize the use of energy from Resources providing Regulation Service.  (2) The ERCOT LFC system shall deploy Regulation Service, Responsive Reserve (RRS), and ERCOT Contingency Reserve Service (ECRS) as necessary in accordance with Protocol Section 6.5.7.6.2, LFC Deployment, to meet North American Electric Reliability Corporation (NERC) Reliability Standards. ERCOT shall purchase Regulation Service to provide satisfactory frequency control performance for the ERCOT Region. ERCOT shall determine the satisfactory amount of Regulation Service, required by statistical analysis of possible Resource Outages and Load forecast error, to expect operation of 95% of hours without deploying RRS.  (3) QSEs shall use Automatic Generation Control (AGC) to direct the output of Resources providing Regulation. |

***2.2.6 Power System Stabilizers***

(1) Synchronously interconnected Generation Resources and synchronously interconnected ESRs with Power System Stabilizers (PSSs) shall keep their PSSs in-service (“On” or energized and performing as designed by the manufacturer) unless the PSS is installed but not in service as described in paragraph (4)(a)(ii) below. When available, the PSS shall be active and responsive at all times the Resource is synchronized to the ERCOT Transmission Grid and operating at or above its Low Sustained Limit (LSL). However, if the PSS of a Resource is set to be active and responsive at a point above the LSL for technical reasons, the Resource may request ERCOT to allow an exception to the requirement that the PSS be active anytime the Resource is at or above its LSL. In order to obtain the exception, the Resource shall notify ERCOT and provide the necessary technical information to ERCOT to justify a higher activation point for the PSS.

(2) Resource Entities shall notify their QSEs of any change in PSS status (e.g. PSS unavailability due to maintenance or failure and when the PSS returns to normal operation). QSEs shall notify ERCOT and the TO at the Point of Interconnection (POI) of any change in PSS status and shall supply PSS status logs to ERCOT upon request per Protocol Section 6.5.5.1, Changes in Resource Status.

(3) Synchronously interconnected Generation Resources and synchronously interconnected ESRs greater than 10 MW installed after January 1, 2008 and on or before December 1, 2010 shall install a PSS and place the PSS in service by June 1, 2011. Synchronously interconnected Generation Resources and synchronously interconnected ESRs greater than 10 MW installed after December 1, 2010 shall install a PSS and place the PSS in-service prior to the Resource Commissioning Date of the Generation Resource or ESR. The Generation Resource or ESR shall establish PSS settings to dampen modes with oscillations within the range of 0.2 Hz to 2 Hz. The PSS settings shall be tested and tuned to ensure the PSS has appropriate damping characteristics. Final PSS settings shall be provided to ERCOT and the TSP within 30 days of the PSS in-service date.

(4) Synchronously interconnected Generation Resources and synchronously interconnected ESRs greater than 10 MW installed before January 1, 2008 are subject to the following requirements:

(a) All Generation Resources and ESRs that are in this category shall notify ERCOT and the TSP:

(i) Whether or not a PSS has been installed; and

(ii) Whether or not PSS settings have been determined and the PSS has been or will be placed in-service.

(b) If a PSS was in-service prior to January 1, 2008, the PSS shall remain in-service with the established PSS settings, provided that ERCOT may direct the Generation Resource or ESR to modify the settings. The PSS settings shall be tested and tuned to ensure the PSS has appropriate damping characteristics.

(c) If a PSS is newly installed and/or placed in-service the Generation Resource or ESR shall establish PSS settings to dampen modes with oscillations within the range of 0.2 Hz to 2 Hz. The PSS settings shall be tested and tuned to ensure the PSS has appropriate damping characteristics. Final PSS settings shall be provided to ERCOT and the TSP within 30 days of the PSS in-service date.

(5) If an excitation system on a synchronously interconnected Generation Resource or synchronously interconnected ESR greater than 10 MW is modified or replaced after January 1, 2008, the Resource shall install a PSS, establish PSS settings to dampen modes with oscillations within the range of 0.2 Hz to 2 Hz, and place the PSS in-service. The settings shall be tested and tuned to ensure the excitation system has appropriate damping characteristics. Final PSS settings shall be provided to ERCOT and the TSP within 30 days of the PSS in-service date.

(6) If it is determined that a change in PSS settings or the addition of a PSS to a synchronously interconnected Generation Resource or synchronously interconnected ESR would improve overall system performance, ERCOT shall coordinate with the Resource owner to determine appropriate settings. Within 180 days of determining appropriate settings, the Resource owner shall revise the PSS setting and/or install the PSS. Any PSS setting established pursuant to this section shall be established to dampen modes with oscillations as directed by ERCOT and place the PSS in-service. Final PSS settings shall be provided to ERCOT and the TSP within 30 days of the PSS in-service date.

(7) At least every ten calendar years, Resource Entities shall conduct a PSS test or verify PSS performance based on operational data for the purpose of model verification on PSSs. All new synchronously interconnected Generation Resources and synchronously interconnected ESR shall conduct a PSS test within five years of the initial PSS test that was approved as part of the commissioning process. All subsequent tests shall be conducted on a ten year cycle. Additionally, if PSS equipment characteristics are modified, the Resource Entity shall conduct a performance test within 120 days of the modification. Industry accepted testing techniques shall be used for testing, measuring and calculating the modeling parameters. The test report must list the test(s) conducted and include the operational data used to verify the modeling parameters. Any models created from the test data must be a standard PSS/E dynamic model or ERCOT and TSP approved user written model. Final PSS settings shall be provided to ERCOT and the TSP within 30 days of the PSS in-service date.

(a) Resource Entities will provide the test data or verified dynamic models to ERCOT by submittal to the NDCRC application located on the MIS Secure Area by updating its Resource Registration information respectively.

(8) An exemption may be granted for the testing requirements listed above if the Resource on which the PSS is installed has a current ANCF, as calculated per paragraph (4) of Section 2.2.5, Automatic Voltage Regulators, of 5% or less over the most recent three calendar years preceding the planned testing calendar year. At the end of this ten year timeframe, the current average three year ANCF (for years eight, nine, and ten) will be examined by ERCOT to determine if the exemption can be declared for the next ten year period. If no longer eligible for the ANCF exemption, then model verification must be completed within 365 calendar days of the date the capacity factor exemption expired. Under certain operating conditions, ERCOT may require a ten year test even if the current average three year ANCF is below the 5% threshold.

(9) The results of PSS tests or PSS performance verification shall be supplied to ERCOT and the TSP within 30 days of a request from ERCOT.

***2.7.6 Unit Dispatch Beyond the Corrected Unit Reactive Limit or Unit Reactive Limit***

(1) Each Generation Resource and Energy Storage Resource (ESR) shall respond to ERCOT-instructed voltage control, including exceeding its CURL or URL. For multi-generator buses, ERCOT shall not instruct any single Generation Resource or ESR to operate beyond its CURL or URL until all Generation Resources and ESRs On-Line and interconnected at the same transmission bus, have been instructed to their respective CURLs or URLs.

***3.2.2 Changes in Resource Status***

(1) QSEs shall verbally notify ERCOT of unplanned changes in the status of a Resource as soon as practicable following the event as referenced in Protocol Section 6.5.5.1, Changes in Resource Status.

(2) QSEs shall verbally notify ERCOT and/or Transmission Service Provider (TSP) of equipment changes that affect the reactive capability of an operating Generation Resource or Energy Storage Resource (ESR).

(3) QSEs shall submit a Current Operating Plan (COP) in accordance with Protocol Section 3.9, Current Operating Plan (COP).

***3.3.1 Unit Capability Requirements***

(1) In the event that a QSE fails to meet Protocol Section 8.1.1.2, General Capacity Testing Requirements, which requires Seasonal unit capability reporting and testing, ERCOT shall provide this QSE with Notice of its failure to meet the Protocols. This Notice shall be sent to the primary contact of the QSE representing the Generation Resource or Energy Storage Resource (ESR) via email. In addition to this written Notice, ERCOT shall make a reasonable effort to notify the QSE via telephone.

(2) ERCOT shall allow the QSE three days to correct the omission by submitting ERCOT approved test results. If the Resource in question is operated during these three days, and no test results are provided to ERCOT, then the QSE shall be disqualified from provision of Ancillary Services.

(3) If the Resource is not operated and included in a QSE Current Operating Plan (COP) after the notification of the Protocol violation, then ERCOT shall not disqualify the Ancillary Service provider unless or until the Resource is operated and included in the COP that might be depended upon for Ancillary Services.

**4.1 Introduction**

(1) Emergency operation is intended to address operating conditions under which the reliability of the ERCOT System is inadequate and there is no solution readily apparent. During a declared system emergency, ERCOT can instruct Transmission Operators (TOs) and Qualified Scheduling Entities (QSEs) to take specific operating actions that would otherwise be discretionary. Upon receiving a Verbal Dispatch Instruction (VDI) from ERCOT, and in compliance with these Operating Guides, the QSEs shall direct relevant Resources or groups of Resources to respond to the instruction. ERCOT shall coordinate with QSEs and TOs to assure that necessary actions are taken to maintain reliability.

(2) It is essential that good, timely, and accurate communication routinely occur between ERCOT, TOs, and QSEs. QSE and TO personnel shall report unplanned equipment status changes as outlined in this Section. ERCOT System Operators may ask for status updates as required in order to gather information to make decisions on system conditions to determine what type of emergency communication may be appropriate.

(3) ERCOT may issue communications in the form of Operating Condition Notices (OCNs), Advisories, Watches and Emergency Notices. These communications may relate to but are not limited to, weather, transmission, computer failure, or generation information. ERCOT shall specify the severity of the situation, the area affected, the areas potentially affected, and the anticipated duration of the Emergency Condition. These communications will be issued by ERCOT to inform all TOs and QSEs of the current operating situation. TOs will notify their represented Transmission Service Providers (TSPs) and Load Serving Entities (LSEs). QSEs will in turn notify the appropriate Resources, Retail Electric Providers (REPs) and LSEs. QSEs and TOs shall establish and maintain internal procedures for contingency preparedness or to expedite the resolution of the conditions communicated by ERCOT that threaten system reliability.

(4) Before deciding which communication to issue, ERCOT must consider the possible severity of the operating situation before an Emergency Condition occurs. If practicable, the market shall be allowed to attempt to mitigate or eliminate any possible Emergency Condition. ERCOT has the responsibility to issue the appropriate communications to facilitate a solution by Market Participants.

**4.3 Operation to Maintain Transmission System Security**

(1) ERCOT shall continue to operate according to Security Criteria outlined in Section 2.2.2, Security Criteria, unless an Emergency Condition has been declared by ERCOT.

(2) Transmission Overload – ERCOT can:

(a) Order adjustment to unit generation schedules, switching of Transmission Elements or Load interruption to relieve the overloaded Transmission Element;

(b) Order a Transmission Element whose loss would not have a significant impact on the reliability of transmission system switched out to increase interconnected system transfers.

(3) Violation of security criteria – ERCOT can order changes to unit dispatch or commitment to eliminate or avoid a security criteria violation. Normally these changes should be performed through market control mechanisms including Security-Constrained Economic Dispatch (SCED) or Reliability Unit Commitment (RUC) as described in the Protocols, but if an ERCOT Operator finds these mechanisms insufficient to resolve the violation, the ERCOT Operator may require any other action necessary to address the violation.

(4) Partial Blackout or Blackout – ERCOT shall implement Black Start procedures.

***4.5.1 General***

(1) At times it may be necessary to reduce ERCOT System demand because of a temporary decrease in available electricity supply. The reduction in supply could be caused by emergency Outages of generators, transmission equipment, or other critical facilities; by short-term unavailability of fuel or generation; or by requirements or orders of government agencies. To provide an orderly, predetermined procedures for curtailing Demand during such emergencies, ERCOT shall initiate and coordinate the implementation of the Energy Emergency Alert (EEA) in accordance with Protocol Section 6.5.9.4, Energy Emergency Alert.

(2) The goal of the EEA is to provide for maximum possible continuity of service while maintaining the integrity of the ERCOT System to reduce the chance of cascading outages.

***4.5.2 Operating Procedures***

(1) The ERCOT System Operators have the authority to make and carry through decisions that are required to operate the ERCOT System during emergency or adverse conditions. ERCOT will have sufficiently detailed operating procedures for emergency or short supply situations and for restoration of service in the event of a Partial Blackout or Blackout. These procedures will be distributed to the personnel responsible for performing specified tasks to handle emergencies, remedy short supply situations, or restore service. Transmission Service Providers (TSPs) will develop procedures to be filed with ERCOT describing implementation of ERCOT requests in emergency and short supply situations, including interrupting Load, notifying others and restoration of service.

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| ***[NOGRR177: Replace paragraph (1) above with the following upon system implementation of NPRR857:]***  (1) The ERCOT System Operators have the authority to make and carry through decisions that are required to operate the ERCOT System during emergency or adverse conditions. ERCOT will have sufficiently detailed operating procedures for emergency or short supply situations and for restoration of service in the event of a Partial Blackout or Blackout. These procedures will be distributed to the personnel responsible for performing specified tasks to handle emergencies, remedy short supply situations, or restore service. Transmission Service Providers (TSPs) and Direct Current Tie Operators (DCTOs) will develop procedures to be filed with ERCOT describing implementation of ERCOT requests in emergency and short supply situations, including interrupting Load, notifying others and restoration of service. |

(2) ERCOT and each TSP will endeavor to maintain transmission ties intact if at all possible. This will:

(a) Permit rendering the maximum assistance to an area experiencing a deficiency in generation;

(b) Minimize the possibility of cascading loss to other parts of the system; and

(c) Assist in restoring operation to normal.

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| ***[NOGRR177: Replace paragraph (2) above with the following upon system implementation of NPRR857:]***  (2) ERCOT and Transmission Operators (TOs) will endeavor to maintain transmission ties intact if at all possible. This will:  (a) Permit rendering the maximum assistance to an area experiencing a deficiency in generation;  (b) Minimize the possibility of cascading loss to other parts of the system; and  (c) Assist in restoring operation to normal. |

(3) ERCOT's operating procedures will meet the following goals while continuing to respect the confidentiality of market sensitive data. If all goals cannot be respected simultaneously then the priority order listed below shall be respected:

(a) Maintain station service for nuclear generating facilities;

(b) Securing startup power for power generating plants;

(c) Operating generating plants isolated from ERCOT without communication;

(d) Restoration of service to critical Loads such as:

(i) Military facilities;

(ii) Facilities necessary to restore the electric utility system;

(iii) Law enforcement organizations and facilities affecting public health; and

(iv) Communication facilities.

(e) Maximum utilization of ERCOT System capability;

(f) Utilization of Ancillary Services to the extent permitted by ERCOT System conditions;

(g) Utilization of the market to the fullest extent practicable without jeopardizing the reliability of the ERCOT System;

(h) Restoration of service to all Customers following major system disturbances, giving priority to the larger group of Customers; and

(i) Management of Interconnection Reliability Operating Limits (IROLs) shall not change.

***4.5.3 Implementation***

(1) ERCOT shall be responsible for monitoring system conditions, initiating the EEA levels below, notifying all Qualified Scheduling Entities (QSEs) representing Resources and Transmission Operators (TOs), and coordinating the implementation of the EEA conditions while maintaining transmission security limits. QSEs and TOs will notify all the Market Participants they represent of each declared EEA level.

(2) During the EEA, ERCOT has the authority to obtain energy from non-ERCOT Control Areas using Direct Current Tie(s) (DC Tie(s)) or by using Block Load Transfers (BLTs) to move load to non-ERCOT Control Areas. ERCOT maintains the authority to curtail energy schedules flowing into or out of the ERCOT System across the DC Ties in accordance with North American Electric Reliability Corporation (NERC) scheduling guidelines.

(3) ERCOT, at management’s discretion, may at any time issue an ERCOT-wide appeal through the public news media for voluntary energy conservation.

(4) There may be insufficient time to implement all levels in sequence. ERCOT may immediately implement EEA Level 2 when clock-minute average system frequency falls below 59.91 Hz for 15 consecutive minutes. ERCOT may immediately implement Level 3 of the EEA any time the clock-minute average system frequency falls below 59.91 Hz for 20 consecutive minutes or when steady-state frequency falls below 59.8 Hz for any duration of time. ERCOT shall immediately implement Level 3 any time the steady-state frequency is below 59.5 Hz for any duration.

(5) Percentages for Level 3 Load shedding will be based on the previous year’s TSP peak Loads, as reported to ERCOT, and will be reviewed by ERCOT and modified annually.

(6) The ERCOT System Operator shall declare the EEA levels to be taken by QSEs and TSPs. QSEs and TSPs shall implement actions under that level (and all above if not previously accomplished) and if ordered by the ERCOT shift supervisor or his designate, shall report back to the ERCOT System Operator when the requested level has been completed.

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| ***[NOGRR177: Replace paragraph (6) above with the following upon system implementation of NPRR857:]***  (6) The ERCOT System Operator shall declare the EEA levels to be taken by QSEs, TSPs, and DCTOs. QSEs, TSPs, and DCTOs shall implement actions under that level (and all above if not previously accomplished) and if ordered by the ERCOT shift supervisor or his designate, shall report back to the ERCOT System Operator when the requested level has been completed. |

(7) During EEA Level 3, ERCOT must be capable of manually shedding sufficient firm Load to arrest frequency decay and to prevent tripping of generators. The amount of manual firm Load to be shed may vary depending on ERCOT Transmission Grid conditions during the event. Each TSP will be capable of manually shedding its allocation of firm Load, without delay. The maximum time for the TSP to interrupt firm Load will depend on how much Load is to be shed and whether the Load is to be interrupted by Supervisory Control and Data Acquisition (SCADA) or other, non-SCADA-controlled methods. Since the need for firm Load shed is immediate, interruption by SCADA is preferred. Each TO, TSP, and Transmission and/or Distribution Service Provider (TDSP) and their designated agents will comply with the following requirements when implementing an ERCOT instruction to shed firm Load:

(a) Load interrupted manually by SCADA will be shed without delay upon receipt of a Load shed instruction and in a time period not to exceed 30 minutes after receipt of the Load shed instruction for each Entity’s portion of every Load shed instruction. SCADA-controlled Load shed is preferred to be utilized by the TO and/or TDSP(s) before non-SCADA-controlled Load shed when executing a Load shed instruction;

(b) If sufficient amounts of SCADA-controlled Load are not available to fulfill an Entity’s manual Load shed instruction, the TO and/or TDSP(s) shall complete, if applicable, the remaining manual Load shed through non-SCADA-controlled Load shed methods without delay upon receipt of a Load shed instruction and in a time period not to exceed one hour after receipt of the Load shed instruction. A TO shall notify ERCOT if its SCADA-controlled Load shed capabilities have been exhausted; and

(c) If determined appropriate by the TO and as soon as practicable, the TO and/or TDSP(s) should restore SCADA-controlled Load by shedding non-SCADA-controlled Load not shed in paragraph (b) above, in an effort to make SCADA-controlled Load available for a potential subsequent Load shed instruction.

(8) Each TSP, or its designated agent, will provide ERCOT a status report of Load shed progress within 30 minutes of the time of ERCOT’s instruction or upon ERCOT’s request.

(9) During EEA Level 2 or 3, for those constraints that meet the criteria identified in paragraph (3)(a) of Section 4.5.3.1, General Procedures Prior to EEA Operations, ERCOT may control the post-contingency flow to within the 15-Minute Rating in Security-Constrained Economic Dispatch (SCED). After Physical Responsive Capability (PRC) is restored to at least 3,000 MW or the Emergency Condition has ended, whichever is later, and ERCOT has determined that system conditions have improved such that the chance of re-entering into an EEA Level 2 or 3 is low, ERCOT shall restore control to the post-contingency flow to within the Emergency Rating for these constraints that utilized the 15-Minute Rating in SCED.

(10) During EEA Level 2 or 3, for those constraints that meet the criteria identified in paragraph (3)(b) of Section 4.5.3.1, ERCOT shall continue to enforce constraints associated with double-circuit contingencies throughout an EEA if the double-circuit failures are determined to be at high risk of occurring, due to system conditions. For all other double-circuit contingencies identified in paragraph (3)(b) of Section 4.5.3.1, ERCOT will enforce only the associated single-circuit contingencies during EEA Level 2 or 3. ERCOT shall resume enforcing such constraints as a double-circuit contingency after PRC is restored to at least 3,000 MW or the Emergency Condition has ended, whichever is later, and ERCOT has determined that system conditions have improved such that the chance of re-entering into an EEA Level 2 or 3 is low. For constraints related to stability limits that are not IROLs, ERCOT may elect not to enforce double-circuit contingencies during EEA Level 3 only.

**4.5.3.2 General Procedures During EEA Operations**

(1) ERCOT Control Area authority will re-emphasize the following operational practices during EEA operations to minimize non-performance issues that may result from the pressures of the emergency situation.

(a) ERCOT shall suspend Ancillary Service obligations that it deems to be contrary to reliability needs;

(b) ERCOT shall notify each QSE representing Resources and TO via ERCOT QSE and TO Hotlines of each declared EEA level and shall post the declared EEA level electronically to the ERCOT website;

(c) QSEs and TOs shall notify each represented Market Participant of declared EEA level;

(d) ERCOT, QSEs and TSPs shall continue to respect confidential market sensitive data;

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| ***[NOGRR177: Replace paragraph (d) above with the following upon system implementation of NPRR857:]***  (d) ERCOT, QSEs, TSPs, and DCTOs shall continue to respect confidential market sensitive data; |

(e) QSEs shall update Current Operating Plans (COPs) to limit or remove capacity when unexpected start-up delays occur or when ramp limitations are encountered;

(f) QSEs shall report when On-Line or available capacity is at risk due to adverse circumstances;

(g) QSEs, TSPs, and all other Entities must not suspend efforts toward expeditious compliance with the applicable EEA level declared by ERCOT nor initiate any reversals of required actions without ERCOT authorization;

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| ***[NOGRR177: Replace paragraph (g) above with the following upon system implementation of NPRR857:]***  (g) QSEs, TSPs, DCTOs, and all other Entities must not suspend efforts toward expeditious compliance with the applicable EEA level declared by ERCOT nor initiate any reversals of required actions without ERCOT authorization; |

(h) ERCOT shall define procedures for determining the proper redistribution of reserves during EEA operations; and

(i) QSEs shall not remove an On-Line Generation Resource or Energy Storage Resource (ESR) without prior ERCOT authorization unless such actions would violate safety, equipment, or regulatory or statutory requirements. Under these circumstances, QSEs shall immediately inform ERCOT of the need and reason for removing the On-Line Resource from service.

**5.1 System Modeling Information**

(1) Information on existing and future ERCOT System components and topology is necessary for ERCOT to create databases and perform tests as outlined in these criteria. To ensure that such information is made available to ERCOT, the following actions by Market Participants are required:

(a) Each Transmission Service Provider (TSP), or its Designated Agent, shall provide accurate modeling information for all Transmission Facilities owned or planned by the TSP. The information provided shall include, but not be limited to, the following:

(i) Information necessary to represent the TSP’s Transmission Facilities in any model of the ERCOT Transmission Grid whose creation has been approved by ERCOT, including modeling information detailed in procedures of the Steady State Working Group (SSWG), Dynamics Working Group (DWG), and System Protection Working Group (SPWG);

(ii) Identification of a designated contact person, generally regarded as the working group TSP representative, responsible for providing answers to questions ERCOT may have regarding the information provided; and

(iii) TSP owned or operated Transmission Facility data provided and used to accurately represent a Transmission Facility in a model shall be consistent to the extent practicable with data provided and used to represent that same Transmission Facility in any other model created to represent a time period during which the Transmission Facility is expected to be physically identical. All existing transmission lines’ and transformers’ impedances, or equivalent branch circuit impedance, and Ratings shall be identical, to the extent practicable. If all normally closed breakers and switches are closed and normally open breakers and switches are open in the Network Operations Model, the calculated line flows between substations in the Annual Planning Model shall be consistent, when all models use the same load magnitude and distribution, generation commitment and dispatch, and Voltage Profile.

(b) Each TSP, or its Designated Agent, owning or planning Transmission Facilities shall attend the scheduled meetings and otherwise participate in the activities of the SSWG, DWG, and the SPWG, unless specifically exempted from these activities by ERCOT.

(c) Each Generation Resource and Energy Storage Resource (ESR), or a Designated Agent for the Resource, shall provide accurate modeling information for each existing or proposed Resource meeting the criteria for inclusion in the SSWG, DWG, and SPWG base cases for which it is the majority owner. The information provided shall include, but not be limited to, the following:

(i) Information necessary to represent the Resource’s generation and interconnection facilities in any model of the ERCOT System whose creation has been approved by ERCOT, including modeling information detailed in procedures of the SSWG, DWG, and SPWG; and

(ii) Identification of a designated contact person responsible for providing answers to questions ERCOT may have regarding the information provided.

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| ***[NOGRR177: Replace paragraph (c) above with the following upon system implementation of NPRR857:]***  (c) Each Generation Resource, Energy Storage Resource (ESR), or Direct Current Tie Operator (DCTO), or a Designated Agent for the Resource or DCTO, shall provide accurate modeling information for each existing or proposed Resource or Transmission Facility meeting the criteria for inclusion in the SSWG, DWG, and SPWG base cases for which the Resource or DCTO is the majority owner. The information provided shall include, but not be limited to, the following:  (i) Information necessary to represent the Resource’s generation and interconnection facilities and the DCTO’s Transmission Facilities in any model of the ERCOT System whose creation has been approved by ERCOT, including modeling information detailed in procedures of the SSWG, DWG, and SPWG; and  (ii) Identification of a designated contact person responsible for providing answers to questions ERCOT may have regarding the information provided. |

(d) Typical or representative information may be provided for planned facility additions or modifications for use in the SSWG, DWG, and SPWG base cases, but such information shall be revised using actual design or construction information in accordance with the time line for Network Operations Model changes outlined in Protocol Section 3.10.1, Time Line for Network Operations Model Changes.

(e) Congestion Revenue Right (CRR) Network Model Outage determination uses network topology of the CRR Network Model identified by ERCOT. This must include Outages of Transmission Elements with a status of approved or accepted by ERCOT at the time the CRR Network Model is being built and that demonstrate significant impact to the transfer capability during the effective period.  ERCOT will consider including Outages in the CRR Network Model that are scheduled to occur in the relevant time period and meet one or more of the following criteria:

(i) Consecutive or continuous approved or accepted Outages greater than or equal to five days;

(ii) Approved or accepted Outages which include Transmission Elements included in the definition of a Hub;

(iii) Approved or accepted Outages which include Transmission Elements in a 345 kV Transmission Facility;

(iv) Approved or accepted Outages that require the use of a Block Load Transfer (BLT); and

(v) Any other approved or accepted Outage that has been determined by ERCOT to carry a substantial risk of causing significant congestion.

(f) As set forth in Protocol Section 7.5.1, Nature and Timing, all Outages included in the CRR Network Model shall be posted on the Market Information System (MIS) Secure Area consistent with the model posting requirements and with accompanying cause and duration information, as indicated in the Outage Scheduler.

**6.1.2.2 Fault Recording and Sequence of Events Recording Equipment Location Requirements**

(1) The location criteria listed below apply to Transmission Facilities operated at or above 100 kV unless otherwise specified. The Facility owner, whether a Transmission Facility owner, a Generation Resource owner, or an Energy Storage Resource (ESR) owner, shall, as applicable, install fault recording and sequence of events recording equipment at the following 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) Locations operating at or above 60 kV, as defined below.

(i) Interconnections with Control Areas outside the ERCOT Region;

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

(iii) All switchyards owned by a Generation Resource or ESR connected to the ERCOT System with an aggregated gross generating nameplate capacity above 100 MVA.

(d) For locations that have experienced an abnormal trip or immediate Load 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)) after a fault:

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

(ii) The interconnecting TSP or DSP shall 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 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.

(e) For any 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 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 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 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.

(2) Transmission Facility owners or Generation Facility owners shall install the applicable fault recording and sequence of events recording equipment identified in paragraph (1) above as soon as practicable.

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| ***[NOGRR255: Replace paragraph (2) above with the following no earlier than August 1, 2026:]***  (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. |

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| ***[NOGRR255: Delete paragraph (2) no earlier than August 1, 2028 and renumber accordingly.]*** |

(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.

6.1.2.3 Fault Recording and Sequence of Events Recording Data Requirements

(1) Each Transmission Facility owner, Generation Resource owner, and ESR 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:

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

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

(c) For transformers 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, Generation Resource owner, and ESR owner shall have sequence of events recording data per the following requirements:

(a) Circuit breaker position (open/close) for each circuit breaker 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; and

(b) The following data 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 fault recording data 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, active and reactive power on low or high side of the MPT;

(e) If applicable, 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.

(5) For each requested Facility identified by ERCOT in paragraphs (1)(d) and (1)(e) in Section 6.1.2.2, 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, Generation Resource owner, and ESR owner shall, upon request, provide to ERCOT fault recording and sequence of events recording data for the Transmission Elements identified in these requirements as follows:

(a) Data shall be maintained and retrievable for at a minimum:

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

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

(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 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 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 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.

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

**6.1.3.1.2 Dynamic Disturbance Recording Equipment Location Requirements**

(1) ERCOT shall identify and provide notification to Facility owners who shall install and maintain dynamic disturbance recording equipment at the following locations:

(a) A Generation Resource(s) that is not an IBR and ESR(s) with:

(i) Gross individual nameplate rating greater than or equal to 500 MVA; or

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

(b) Any Transmission Element part of a stability-related (angular or voltage) 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, on the alternating current side of a converter;

(d) One or more Transmission Elements 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 UVLS program.

(2) ERCOT shall identify, and notify Facility owners of, a minimum dynamic disturbance recording coverage, including 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.

**6.1.3.1.3 Dynamic Disturbance Recording Data Recording and Redundancy Requirements**

(1) Recorded electrical quantities shall determine the following:

(a) For Transmission Facilities meeting the requirements in Section 6.1.3.1.2, Dynamic Disturbance Recording Equipment Location Requirements:

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

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

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

(b) For Generation Resource owner and ESR owner locations 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 on the high or low side of a MPT;

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

(iv) 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 electrical quantities shall maintain and retain that data, at a minimum:

(a) A rolling ten calendar day period for all data;

(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 event analysis or review.

(2) Each affected Market Participant shall provide to ERCOT, upon request, dynamic disturbance recording data as follows:

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

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

(c) Dynamic disturbance recording 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.

***6.1.5 Maintenance and Testing 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 maintain and test its equipment as follows:

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

(b) To ensure data stored locally is available upon request by verifying data availability and quality at least once every 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, Section 6.1.3, and Section 6.1.4 shall, within 90 calendar days 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 recording capabilities.

***6.2.3 Performance Analysis Requirements for ERCOT System Facilities***

(1) All ERCOT System disturbances (unwanted trips, faults, and protective relay system operations) shall be analyzed by the affected facility owner(s) promptly and any deficiencies shall be investigated and corrected.

(2) All protective relay system misoperations and all associated corrective actions in Generation Resource systems, Energy Storage Resource (ESR) systems, or Transmission Facility systems 100 kV and above shall be documented, and documentation shall be supplied by the affected Facility owner(s) to ERCOT per the timeline established in paragraph (6) below or upon request. Any of the following events constitute a reportable protective relay system misoperation:

(a) Failure to Trip – Any failure of a protective relay system to initiate a trip to the appropriate terminal when a fault is within the intended zone of protection of the device (zone of protection includes both the reach and time characteristics). Lack of targeting, such as when a high-speed pilot system is beat out of high-speed zone is not a reportable misoperation. Furthermore, if the fault clearing is consistent with the time normally expected with proper functioning of at least one protection system, then a primary or backup protection system failure to operate is not required to be reported;

(b) Slow Trip – An operation of a protective relay system for a fault in the intended zone of protection where the relay system initiates tripping slower than the system design intent;

(c) Unnecessary Trip During a Fault – Any unnecessary protective relay system operation for a fault not within the zone of protection. Operation as backup protection for a fault in an adjacent zone that is not cleared within the specified time for the protection for that adjacent zone is not a reportable operation; and

(d) Unnecessary Trip Other Than Fault – Any unnecessary protective relay system operation when no fault or other abnormal condition has occurred. Note that an operation that occurs during on-site maintenance, testing, construction and/or commissioning activities is not a reportable misoperation.

(3) Any of the following events do not constitute a reportable protective relay system misoperation:

(a) Trip Initiated by a Control System – Operations which are initiated by control systems (not by protective relay system), such as those associated with generator controls, or turbine/boiler controls, Static Var Compensators, Flexible AC Transmission devices, HVDC terminal equipment, circuit breaker mechanism, or other facility control systems, are not considered protective relay system misoperations;

(b) Facility owner authorized personnel action that directly initiates a trip is not considered a misoperation. It is the intent of this reporting process to identify misoperations of the protective relay system as it interrelates with the electrical system, not as it interrelates to personnel involved with the protective relay system. If an individual directly initiates an operation, it is not counted as a misoperation (i.e., unintentional operation during tests); however, if a technician leaves trip test switches or cut-off switches in an inappropriate position and a system fault or condition causes a misoperation, this would be counted as a protective relay system misoperation; and

(c) Failure of Relay Communications – A communication failure in and of itself is not a misoperation if it does not result in misoperation of the associated protective relay system.

(4) All Remedial Action Scheme (RAS) misoperations shall be documented, including corrective actions, and the documentation supplied to ERCOT, the Reliability Monitor, and the NERC Regional Entity, per the timeline established in paragraph (1) of Section 11.2.1, Reporting of RAS Operations. Any of the following events constitute a reportable RAS misoperation:

(a) Failure to Operate – Any failure of a RAS to perform its intended function within the designed time when power system conditions intended to trigger the RAS occur;

(b) Unnecessary Operation – Any operation of a RAS that occurs without the occurrence of the intended system trigger condition(s);

(c) Unintended System Response – A RAS operates for the system conditions it was designed to operate for but the RAS operation results in an unintended adverse power system response;

(d) Failure to Mitigate – A RAS operates for the system conditions it was designed to operate for but fails to mitigate the power system conditions it was designed to address;

(e) Failure to Arm – Any failure of a RAS to automatically arm itself when power system conditions that are intended to arm the RAS occur; and

(f) Failure to Disarm or Reset – Any failure of a RAS to automatically disarm or reset itself when power system conditions that are intended to disarm the RAS occur.

(5) Transmission Facility owners shall document the performance of their protective relay systems. The performance data reported shall include the total number of protective relay system misoperations and the total number of events.

(6) Protective relay system misoperations shall be reported to ERCOT using either the Relay Misoperations Report form on the ERCOT website or any other form that contains the same information and that is provided in a similar format as the ERCOT Relay Misoperations Report. Relay Misoperation Reports shall be submitted to ERCOT at [shiftsupv@ercot.com](mailto:shiftsupv@ercot.com) on a quarterly basis per the following schedule:

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| --- | --- |
| **Data submission** | **Date\*** |
| Submission of the 1st Quarter data | May 31 |
| Submission of the 2nd Quarter data | August 31 |
| Submission of the 3rd Quarter data | November 30 |
| Submission of 4th Quarter data | February 28 |
| *\*Next Business Day if date specified is a non-Business Day* | |

(7) All Facility owners shall install, maintain, and operate disturbance monitoring equipment in accordance with the requirements in Section 6.1.2.3, Fault Recording and Sequence of Events Recording Data.

***6.2.6.1.1 Dependability***

(1) Except as noted in paragraphs (4) and (5) below, all elements of the ERCOT System operated at 100 kV and above (i.e., lines, buses, transformers, generators, breakers, capacitor banks, etc.) shall be protected by two protective relay systems. Each protective relay system shall be independently capable of detecting and isolating all faults thereon.

(2) The protective relay system design should avoid the use of components common to the two protective relay systems. Areas of common exposure should be kept to a minimum to reduce the possibility of both protective relay systems being disabled by a single contingency.

(3) The use of two identical protective relay systems is not generally recommended, due to the risk of simultaneous failure of both protective relay systems because of design deficiencies or equipment problems.

(4) Breaker failure protection should be provided to trip all necessary local and remote breakers in the event that a breaker fails to clear a fault. This protection need not be duplicated.

(5) On installations where freestanding or column-type current transformers are provided on one side of the breaker only, the protective relay systems should be provided to detect a fault on the primaries of such current transformers. This protection need not be duplicated. Application of freestanding current transformers requires extra care to ensure that the relaying is proper and that the schemes overlap.

***6.2.6.1.6 Analysis of System Performance and Associated Protection Systems***

(1) Relay operation and settings shall be reviewed periodically and whenever significant changes in generating sources, transmission facilities, or operating conditions are anticipated.

(2) Naturally occurring faults and other system disturbances should be analyzed as a source of information as to the health of relay schemes in the facility owner’s system and the ERCOT System. Sources of information usually available are:

(a) Short circuit study for the exact conditions of the fault;

(b) Fault recorder traces;

(c) Sequence of events data recording the opening and closing of contacts in the protective relay scheme and associated communication equipment;

(d) Fault locator data;

(e) SCADA logger output of breaker operation and alarms;

(f) Interviews with operating personnel and/or other witnesses;

(g) Field report of relay flags and breaker counter changes;

(h) Field report of the fault location, if found;

(i) Records of relay setting, relay testing, trip check and energize procedures as carried out, in-service measurements, relay wiring diagrams and schematics, manufacturers' information;

(j) Other utility personnel and System Protection Working Group (SPWG) members; and

(k) Manufacturers' application and design engineers.

(3) Steps that may be followed in analyzing a disturbance include:

(a) Gather data;

(b) Create a time line consisting of events and periods between events;

(c) Compare actual and calculated values of current and voltage during the periods between events;

(d) Compare actual and expected breaker operations and flags;

(e) Choose the least complicated explanation for contradictory information and to fill in missing information;

(f) Gather additional information as indicated to prove or disprove explanations;

(g) Iterate;

(h) Document by issuing a report of all findings, changes, and recommendations; and

(i) After a reasonable time, check back to see if the recommendations have been carried out.

***6.2.6.3.6 Automatic Under-Voltage Load Shedding Protection Systems***

(1) Automatic Under-Voltage Load Shedding (UVLS) systems are classified as protective relay systems. The maintenance requirements, discussed in Section 6.2.5, Maintenance and Testing Requirements for ERCOT System Facilities, apply to UVLS protection systems as well.

(2) The requirement for under-voltage relaying shall be determined by system studies performed/administered by ERCOT designated working groups or equipment owners. The system studies should indicate the following:

(a) Amount of Load to be shed to restore voltage to minimum acceptable level or higher;

(b) The minimum and maximum time delay allowed before automatically shedding Load;

(c) The voltage level(s) at which to initiate automatic relay operation; and

(d) The location(s) for effectively applying UVLS protection systems.

(3) Automatic UVLS protection systems need not be duplicated.

(4) Analyses shall be performed on UVLS schemes by working groups and/or equipment owners as assigned by ERCOT to demonstrate that they are expected to act before generators trip Off-Line due to the protective relay requirements, as specified in paragraph (4)(a) of Section 2.9, Voltage Ride-Through Requirements for Generation Resources and Energy Storage Resources. A specific exemption from this analysis requirement may be provided by the ROS.

(5) Under-voltage protection systems shall be designed to coordinate with other protective devices and control schemes during momentary voltage dips, sustained faults, low voltages caused by stalled motors, motor starting, etc.

(6) Automatic Load restoration for an UVLS operation is not currently utilized in ERCOT.

(7) The UVLS scheme shall be designed to ensure reliable operation. The scheme shall not impede continued operation of any Distribution Generation Resource (DGR) or Distribution Energy Storage Resource (DESR) during a UVLS event, except as permitted by Protocol Section 3.8.6, Distribution Generation Resources (DGRs) and Distribution Energy Storage Resources (DESRs).

(8) In addition, protective relaying for Generation Resources and ESRs must be designed to meet Voltage Ride-Through (VRT) criteria as detailed in Section 2.9.

(9) Restoration of any Load shed by UVLS shall be coordinated with ERCOT.

9.1.2 Compliance with Valid Dispatch Instructions

(1) ERCOT shall produce monthly reports detailing Resource-specific Regulation Service and energy deployment performance, including Load Resources, based on the criteria described in Protocol Section 8.1.1.4.1, Regulation Service and Generation Resource/Controllable Load Resource/Energy Storage Resource Energy Deployment Performance and Ancillary Service Capacity Performance Metrics.

(2) ERCOT shall produce a report for any system-wide deployment of Load Resources on an event basis, within 90 days after the event occurs and shall post it to the MIS Secure Area.

***9.3.2 System and Resource Control***

(1) The following reports shall be posted on the MIS Secure Area:

(a) Resource control metrics:

(i) Total Regulation Up Service (Reg-Up) and Regulation Down Service (Reg-Down) per interval - ERCOT shall develop a monthly report detailing the total amount of Reg-Up energy deployed in the Settlement Interval and by hour and the total amount of Reg-Down energy deployed for each Settlement Interval and by hour of the Operating Day.

(b) Reliability Unit Commitments (RUCs) and deployments:

(i) For each month, ERCOT shall report, Generation Resources committed in each RUC process, the reason for the commitment, Resource name and intervals deployed, and the hours committed for Voltage Support Service (VSS).

(c) Reversal of Base Point instructions to Generation Resources and Energy Storage Resources (ESRs) from interval to interval:

(i) ERCOT shall record and report, on a monthly basis, instances of Dispatch Instructions to Resources not providing Regulation Service in which there is a directional change in Base Point instructions for four consecutive Security-Constrained Economic Dispatch (SCED) intervals for validation and review.

**11.2 Remedial Action Schemes**

(1) Remedial Action Schemes (RASs) are designed to detect abnormal predetermined ERCOT System conditions and automatically take corrective actions to maintain a secure system. Any RAS proposed on or after June 24, 2020 may not be approved or implemented unless ERCOT has first determined that the RAS is necessary to avoid an actual or anticipated violation of transmission security criteria, as defined in Section 2.2.2, Security Criteria, that cannot be resolved through ERCOT market tools.

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| ***[NOGRR215: Replace paragraph (1) above with the following upon system implementation:]***  (1) Remedial Action Schemes (RASs) are designed to detect abnormal predetermined ERCOT System conditions and automatically take corrective actions to maintain a secure system. Any RAS proposed on or after June 24, 2020 may not be approved or implemented unless ERCOT has first determined that the RAS is necessary to avoid an actual or anticipated violation of transmission security criteria, as defined in Section 2.2.2, Security Criteria, that cannot be resolved through ERCOT market tools, or unless the RAS would allow a Generation Resource of the type described in paragraph (3) of Planning Guide Section 4.1.1.7, Minimum Deliverability Criteria, to operate at a level that comports with the minimum deliverability criteria in Planning Guide Section 4.1.1.7. |

(2) The following do not individually constitute a RAS:

(a) Protection systems installed for the purpose of detecting faults on Transmission Elements and isolating the faulted Transmission Elements;

(b) Schemes for automatic Under-Frequency Load Shedding (UFLS) and automatic Under-Voltage Load Shedding (UVLS) comprised of only distributed relays;

(c) Out-of-step tripping and power swing blocking;

(d) Automatic reclosing schemes;

(e) Schemes applied on a Transmission Element for non-fault condition, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage or overload to protect the Transmission Element against damage by removing it from service;

(f) Controllers that switch or regulate one or more of the following: series or shunt reactive devices, flexible alternating current transmission system (FACTS) devices, phase-shifting transformers, variable-frequency transformers, or tap-changing transformers; and that are located at and monitor quantities solely at the same station as the Transmission Element being switched or regulated;

(g) FACTS controllers that remotely switch static shunt reactive devices located at other stations to regulate the output of a single FACTS device;

(h) Schemes or controllers that remotely switch shunt reactors and shunt capacitors for voltage regulation that would otherwise be manually switched;

(i) Schemes that automatically de-energize a line for a non-faults operation when one end of the line is open;

(j) Schemes that provide anti-islanding protection (e.g., protect Load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage);

(k) Automatic sequences that proceed when manually initiated solely by a System Operator;

(l) Modulation of high voltage, direct current (HVDC) or FACTS via supplementary controls, such as angle damping or frequency damping applied to damp local or inter-area oscillation;

(m) Sub-synchronous resonance protection schemes that directly detect sub-synchronous quantities (e.g., currents or torsional oscillations); or

(n) Generation controls such as, but not limited to, Automatic Generation Control (AGC), generation excitation (e.g., Automatic Voltage Regulator (AVR) and Power System Stabilizers (PSSs)), fast valving, and speed governing.

(3) In addition to the requirements in the Protocols and applicable North American Electric Reliability Corporation (NERC) Reliability Standards, RASs shall also meet the following requirements:

(a) A RAS may be proposed by a Transmission Service Provider (TSP) or Resource Entity, and be approved by ERCOT and the TSP(s) and/or Resource Entity(ies) included in the RAS prior to implementation;

(b) The design, implementation, and testing of the RAS shall be coordinated within the RAS Entity;

(c) The RAS shall be automatically armed when appropriate;

(d) The RAS shall not operate unnecessarily;

(e) A RAS designated as a Limited Impact RAS shall be reviewed according to the process described in paragraph (4)(e) below and subject to ERCOT approval;

(f) For a RAS not designated by ERCOT as a Limited Impact RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following as determined by the review process in paragraph (4)(e) below and subject to ERCOT approval:

(i) The ERCOT System shall remain stable;

(ii) Cascading shall not occur;

(iii) Applicable Facility Ratings shall not be exceeded;

(iv) ERCOT System voltages shall be within post-contingency voltage limits and post-contingency voltage deviation limits;

(v) Transient voltage responses shall be within acceptable limits.

(g) To avoid unnecessary RAS operation, the RAS Entity may provide a Real-Time status indication to the owner of any Generation Resource or Energy Storage Resource (ESR) controlled by the RAS to show when the flow on one or more of the RAS monitored Facilities exceeds 90% of the flow necessary to arm the RAS. The cost necessary to provide such status indication shall be the responsibility of the RAS Entity;

(h) The status indication of any automatic or manual arming/activation or operation of the RAS shall be provided as Supervisory Control and Data Acquisition (SCADA) alarm inputs to the owner(s) of any Facility controlled by the RAS;

(i) When a RAS is removed from service, the RAS Entity or a Designated Agent shall immediately notify ERCOT;

(j) When a RAS is returned to service, the RAS Entity or its Designated Agent shall immediately notify ERCOT. ERCOT shall modify its reliability constraints to recognize the availability of the RAS;

(k) The RAS Entity shall telemeter the status indication of the following items by SCADA to ERCOT for incorporation into ERCOT systems:

(i) Any automatic or manual arming/activation or operation of the RAS;

(ii) The in-service/out-of-service status of the RAS; and

(iii) Any additional related telemetry that already exists pertinent to the monitoring of the RAS (e.g. status indication of communications links between associated RAS equipment and the owner’s control center, arming limits of associated RAS equipment); and

(l) The TSP may receive telemetry for a Resource Entity owned RAS through ERCOT or through the RAS Entity, at the option of the TSP. The RAS Entity, at its own cost, must provide telemetry for Resource Entity owned RASs to the TSP upon request.

(4) The RAS Entity shall submit to ERCOT documentation of an existing, modified, proposed, or retiring RAS for review and compilation into an ERCOT RAS database using the form in Section 8, Attachment K, Remedial Action Scheme (RAS) Template. The documentation shall detail the design, operation, modeling, functional testing, and coordination of the RAS with other RASs, Automatic Mitigation Plans (AMPs), protection and control systems. The exit strategy described in the RAS submission shall identify the ERCOT endorsed transmission project or near-term mitigation that will address the constraint.

(a) ERCOT shall conduct a review of each proposed new or modified RAS and each proposed retirement of a RAS. Within five Business Days of receipt, ERCOT shall post the proposal to the Market Information System (MIS) Secure Area and shall issue a Market Notice describing the proposal and inviting submission of Market Participant comments. Within 30 Business Days of receiving the proposal, ERCOT shall complete an evaluation of the proposal in accordance with paragraph (4)(e) below and shall issue a Market Notice approving or rejecting the proposal. ERCOT shall coordinate any additional time needed for the evaluation with the RAS Entity. Additionally, ERCOT shall conduct a review of each existing RAS at least once every three years or as required by changes in system conditions.

(b) The review of a proposed RAS shall be completed before the RAS is placed in service. The timing of placing the RAS into service must be coordinated with and approved by ERCOT. The implementation schedule must be confirmed through submission of a Network Operations Model Change Request (NOMCR) to ERCOT.

(c) Existing RASs that have already undergone at least one review shall remain in service during any subsequent review. Modifications to existing RASs may be implemented upon approval by ERCOT.

(d) The schedule for placing a RAS into service must be coordinated among ERCOT and the RAS Entity, and shall provide sufficient time to perform any necessary functional testing prior to its being placed in service.

(e) For any proposed, modified, or existing RAS, ERCOT’s review of the RAS shall:

(i) Validate that RAS is needed to mitigate the system condition(s) or contingency(ies) for which it was designed, and that the RAS actions, designed timing, and arming conditions mitigate those system condition(s) or contingency(ies);

(ii) Identify any conflicts with the Protocols, NERC Reliability Standards, and this Operating Guide;

(iii) Validate that transient voltage responses are within acceptable limits as established by ERCOT;

(iv) Evaluate and document the consequences of misoperation, incorrect operation, unintended operation, or failure of a RAS. Additionally, validate that the RAS is designed to meet the requirements in paragraphs (3)(e) and (3)(f) above;

(v) Validate that the proposed RAS facilitates periodic testing and maintenance;

(vi) Determine whether or not the RAS is a Limited Impact RAS;

(vii) Validate that the proposed RAS avoids adverse interactions with other RASs, AMPs, protection and control systems, and applicable emergency procedures;

(viii) Evaluate the effects of future bulk electric system modifications on the design and operation of the RAS where applicable;

(ix) Validate the implementation of RAS logic appropriately correlates desired actions (outputs) with events and conditions (inputs);

(x) Validate the mechanism of procedure by which the RAS is armed is clearly described, and is appropriate for reliable arming and operation of the RAS for the conditions and events for which it is designated to operate; and

(xi) Evaluate future transmission project(s) that will eliminate the need for the RAS.

(f) Upon completion of ERCOT’s RAS review, ERCOT shall provide all results and underlying studies to the RAS Entity and each impacted TSP.

(g) If deficiencies are identified for a new, functionally modified, or retiring RAS by ERCOT or other parties’ comments, the RAS Entity shall either submit an amended RAS proposal or withdraw the RAS proposal. The amended RAS proposal shall undergo the review process specified in paragraph (4)(e) above using the 30 Business Day RAS review timeline in paragraph (4)(a) above until the identified deficiencies have been resolved to the satisfaction of ERCOT.

(h) For any proposed retirement of a RAS, ERCOT shall evaluate whether the proposed retirement will cause any reliability concern, including whether the proposed retirement will adversely impact the dispatch of a Generation Resource or ESR subject to the minimum deliverability criteria set forth in Planning Guide Section 4.1.1.7, Minimum Deliverability Criteria. After considering any comments submitted, if ERCOT does not identify any reliability concern, ERCOT shall issue a Market Notice indicating its approval of the proposed retirement of the RAS. If ERCOT does identify a reliability concern or an adverse impact to the dispatch of a Generation Resource or ESR subject to the minimum deliverability criteria set forth in Planning Guide Section 4.1.1.7, ERCOT shall issue a Market Notice denying the retirement.

(i) As part of the ERCOT review, ERCOT may notify the Steady State Working Group (SSWG), the Dynamics Working Group (DWG), and the System Protection Working Group (SPWG) of the RAS proposal, and each working group or any member of each working group may provide any comments, questions, or issues to ERCOT. ERCOT may work with the owner(s) of Facilities affected by the RAS as necessary to address all issues.

(j) ERCOT shall develop a method to include the RAS where practicable in Security-Constrained Economic Dispatch (SCED), Outage coordination, and Reliability Unit Commitment (RUC).

(k) ERCOT’s review shall provide an opportunity for and include consideration of comments submitted by Market Participants affected by the RAS.

(l) ERCOT shall update the RAS database at least once every 12 calendar months.

(5) ERCOT shall provide the results of the RAS evaluation including any identified deficiencies to the RAS Entity and impacted TSPs. If ERCOT’s RAS evaluation identifies a deficiency within six calendar months, the RAS Entity shall develop and submit a corrective action plan, subject to ERCOT approval, to correct the deficiencies. For each plan developed, the RAS Entity shall implement the approved plan, update the plan if actions or timetables change, and notify ERCOT via email at [ras\_cmp@ercot.com](mailto:ras_cmp@ercot.com) if plan actions or timetables change and when the plan is completed.

(6) If ERCOT determines that a RAS is no longer needed, either as part of an ERCOT-initiated review or as a consequence of ERCOT’s determination that a transmission project has addressed the condition(s) or contingency(ies) the RAS was designed to address, ERCOT shall issue a Market Notice proposing to retire the RAS and inviting comments from Market Participants on the proposed retirement. After considering all comments, if ERCOT confirms that the RAS is not needed, then ERCOT shall retire the RAS on a date specified in a separate Market Notice.

(7) The RAS Entity shall perform a functional test of each of its RAS to verify the overall RAS performance and the proper operation of non-protection system components at least once every six calendar years for a RAS not designated as a Limited Impact RAS, and once every 12 calendar years for a RAS designated as a Limited Impact RAS. For any identified deficiencies, the RAS Entity shall develop and submit a corrective action plan within six calendar months, and subject to ERCOT approval, to correct the deficiencies. For each plan developed, the RAS Entity shall implement the approved plan, update the plan if actions or timetables change, and notify ERCOT via email at [ras\_cmp@ercot.com](mailto:ras_cmp@ercot.com) if plan actions or timetables change and when the plan is completed.

***11.2.1 Reporting of RAS Operations***

(1) RAS Entity shall notify ERCOT of all RAS operations. Documentation of RAS failures or misoperations shall be provided to ERCOT using the Relay Misoperation Report form as an email to [ras\_cmp@ercot.com](mailto:ras_cmp@ercot.com). Within 120 calendar days, the RAS Entity shall conduct an analysis of all RAS operations, misoperations, and failures. If deficiencies are identified, the RAS Entity shall develop and submit a corrective action plan within six calendar months, and subject to ERCOT approval, correct the deficiencies. For each plan developed, the RAS Entity shall implement the approved plan, update the plan if actions or timetables change, and notify ERCOT via email at [ras\_cmp@ercot.com](mailto:ras_cmp@ercot.com) if plan actions or timetables change and when the plan is completed. Analysis of RAS operational performance shall include, but is not limited to:

(a) Determination of whether system events or conditions appropriately armed or triggered the RAS;

(b) Determination of whether the RAS responded as designed;

(c) Determination of whether the RAS was effective in mitigating the performance issues it was designed to address; and

(d) Determination of whether the RAS operation resulted in any unintended or adverse system response.

(2) ERCOT shall report all RAS operations and misoperations to the Reliability Monitor for review. RAS arming or activation that ramps generation back is not considered an operation or misoperation with respect to reporting requirements to the Reliability Monitor and the NERC Regional Entity. A misoperation of a RAS with respect to reporting requirements to the Reliability Monitor and the NERC Regional Entity occurs when one of the items specified in paragraph (4) of Section 6.2.3, Performance Analysis Requirements for ERCOT System Facilities, occur. RAS Entities will provide a monthly report to ERCOT by the 15th of each month describing each instance a RAS armed/activated and reset during the previous month. The report will include the date and time of arming/activation and reset. ERCOT shall consolidate the monthly reports and forward to the Reliability Monitor and NERC Regional Entity on a quarterly basis.

(3) If a RAS which removes generation from service operates more than two times within a six month period and the operations are not a direct result of an ERCOT System disturbance or a contingency operation, ERCOT may require the Resource Entity(ies) representing the Generation Resource or ESR to decrease the available capability on the affected Resource(s). The amount of available capacity to be decreased shall be determined by ERCOT. The decreased available capacity on the Resource(s) shall remain until the Resource Entity(ies) provides documentation that demonstrates the Resource(s) can properly control output in a pre-contingency or normal ERCOT System condition.