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| NOGRR Number | [164](http://www.ercot.com/mktrules/issues/NOGRR164) | NOGRR Title | Alignment with NPRR 792, Removing Special Protection Scheme (SPS) and Adding Remedial Action Scheme (RAS) |

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| --- | --- |
| Date | September 21, 2016 |

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| Submitter’s Information |
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| Market Segment | Municipal |

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| Comments |

Austin Energy appreciates the opportunity to offer additional comments on Nodal Operating Guide Revision Request (NOGRR) 164 and apologizes for the lateness with which these comments are filed. These comments are offered on top of the 9/19/16 ERCOT comments.

Austin Energy’s proposed addition to NOGRR164 is intended to align Nodal Operating Guide language with a new requirement anticipated for NPRR792 for consideration at the October 13, 2016 PRS meeting. Specifically, the proposed addition to Section 11.1(4) would require ERCOT to notify the market in the event that a Remedial Action Scheme, an Automatic Mitigation Plan, or a Remedial Action Plan cannot be modeled in the Network Operations Model.

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| Revised Cover Page Language |

None proposed.

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| **Revised Proposed Guide Language** |

***2.2.7 Turbine Speed Governors***

(1) A Governor shall be in-service whenever the Generation Resource is providing energy to the ERCOT Transmission Grid.

(2) Resource Entities shall conduct Governor performance tests for each Generation Resource or Wind-powered Generation Resource (WGR) at least every two years using one of the test methods or historical methods specified in Section 8, Attachment C, Turbine Governor Speed Tests. The Resource Entity shall then provide test results to ERCOT.

(3) Every effort should be made to maintain Primary Frequency Response. Maintenance tests on Governors shall demonstrate calibration for operation consistent with a generator droop characteristic of no greater than 5% but no less than 2% and Governor Dead-Band no greater than +/- 0.036 Hz.

(4) There are elements that can contribute to poor Primary Frequency Response. These include:

(a) Governor Dead-Band in excess of +/- 0.036 Hz (measured from 60 Hz);

(b) Valve position limits;

(c) Blocked Governor operation;

(d) Control mode;

(e) Adjustable rates or limits;

(f) Boiler/turbine coordinated control or set point control action; and

(g) Automated “reset” or similar control action of the turbine’s MW set point.

(5) Every attempt should be made to minimize the effects of the elements listed in item (4) above on the Governor operation for the duration of all frequency deviations. Each Resource Entity should monitor its Generation Resources to verify these elements do not contribute to a Governor droop characteristic of no greater than 5% but no less than 2%.

(6) If ERCOT determines that ERCOT System reliability would be enhanced, for a defined period of time, ERCOT may direct WGRs under the control of a Remedial Action Scheme (RAS) to limit power increases due to frequency if there is risk of an RAS operation due to a low frequency event.

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| ***[NOGRR143: Replace Section 2.2.7 above with the following upon system implementation:]******2.2.7 Turbine Speed Governors***(1) A Governor shall be in-service whenever the All-Inclusive Generation Resource is connected to the ERCOT Transmission Grid.(2) Generation Resources that have not been evaluated in at least eight Frequency Measurable Events (FMEs) within 36 months shall conduct Governor performance tests for that Generation Resource within 12 months using one of the test methods or historical methods specified in Section 8, Attachment C, Turbine Governor Speed Tests. The Resource Entity shall then provide test results to ERCOT.(3) All-Inclusive Generation Resources shall have a Governor droop characteristic and Governor Dead-Band setting no greater than those shown below in Table 1, Maximum Governor Dead-Band Settings, and Table 2, Maximum Governor Droop Settings, as defined below:**Table 1: Maximum Governor Dead-Band Settings**

|  |  |
| --- | --- |
| **Generator Type** | **Max. Deadband** |
| Steam Turbines withMechanical Governors | +/- 0.034 Hz |
| Hydro Turbines with Mechanical Governors | +/- 0.034 Hz |
| All Other GeneratingUnits/Generating Facilities | +/- 0.017 Hz |
| Controllable Load Resources | +/- 0.036 Hz |

**Table 2: Maximum Governor Droop Settings**

|  |  |
| --- | --- |
| **Generator Type** | **Max. Droop % Setting** |
| Combustion Turbine (Combined Cycle) | 4% |
| All Other GeneratingUnits/Generating Facilities/ Controllable Load Resources | 5% |

(4) If ERCOT determines that ERCOT System reliability would be enhanced, for a defined period of time, ERCOT may direct Wind-powered Generation Resources (WGRs) under the control of a Remedial Action Scheme (RAS) to limit power increases due to frequency if there is risk of an RAS operation due to a low frequency FME. |

***2.9.1 Additional Voltage Ride-Through Requirements for Intermittent Renewable Resources***

(1) All Intermittent Renewable Resources (IRRs) shall also comply with the requirements of this Section, except as follows:

(a) An IRR that interconnects to the ERCOT System pursuant to a Standard Generation Interconnection Agreement (SGIA) (i) executed on or before January 16, 2014 and (ii) under which the IRR provided all required financial security to the TSP on or before January 16, 2014, is not required to meet any high VRT requirement greater than 1.1 per unit voltage unless the interconnected IRR includes one or more turbines that differ from the turbine model(s) described in the SGIA (including any attachment thereto), as that agreement existed on January 16, 2014. Notwithstanding the foregoing, if the Resource Entity that owns or operates an IRR that was interconnected pursuant to an SGIA executed before January 16, 2014, under which the IRR provided all required financial security to the TSP on or before January 16, 2014, demonstrates to ERCOT’s satisfaction that the high VRT capability of the IRR is not lower than the capability of the turbine model(s) described in the SGIA (including any attachment thereto), as that agreement existed on January 16, 2014 that IRR is not required to meet the high VRT requirement in this Section.

(b) An IRR that interconnects to the ERCOT System pursuant to an SGIA executed prior to November 1, 2008 is not required to meet VRT requirements presented in this Section. However, any WGR that is installed on or after November 1, 2008 and that initially synchronizes with the ERCOT System, pursuant to a Standard Generation Interconnection Agreement (SGIA) (i) executed on or before January 16, 2014, and (ii) under which the IRR provided all required financial security to the TSP on or before January 16, 2014 (except for an IRR installed pursuant to an SGIA executed before November 1, 2008) shall be VRT-capable in accordance with the low VRT requirements in this Section and high-voltage requirements in this Section up to 1.1 per unit voltage unless the interconnected IRR includes one or more turbines that differ from the turbine model(s) described in the SGIA (including any attachment thereto), as that agreement existed on January 16, 2014 in which case the IRR shall also be required to comply with the high VRT requirements of this section, subject to the exemption described in paragraph (a), above.

(c) An IRR that is not technically capable of complying with a 1.2 per unit voltage high VRT requirement and that is not subject to either of the exemptions described in paragraphs (a) or (b), above, is not required to meet any high Voltage Ride-Through (VRT) requirement greater than 1.1 per unit voltage until January 16, 2016

(d) Notwithstanding any of the foregoing provisions, an IRR’s VRT capability shall not be reduced over time.

(2) Each IRR shall provide technical documentation of VRT capability to ERCOT upon request.

(3) Each IRR is required to set generator voltage relays to remain in service for at least 0.15 seconds during all transmission faults and to allow the system to recover as illustrated in Figure 1, Default Voltage Ride-Through Boundaries for IRRs, below. Recovery time to 90% of per unit voltage should be within 1.75 seconds. Faults on individual phases with delayed clearing (zone 2) may result in phase voltages outside this boundary but if the phase voltages remain inside this boundary, then generator voltage relays are required to be set to remain connected and recover as illustrated in Figure 1.

(4) Each IRR shall remain interconnected during three-phase faults on the ERCOT System for a voltage level as low as zero volts with a duration of 0.15 seconds as measured at the Point of Interconnection (POI) unless a shorter clearing time requirement for a three-phase fault specific to the generating plant POI is determined by and documented by the TSP in conjunction with the SGIA. The clearing time requirement shall not exceed nine cycles.

(5) Each IRR shall set generator voltage relays to remain interconnected to the ERCOT System during the following high-voltage conditions, as illustrated in Figure 1: any per-unit voltage equal to or greater than 1.175 but less than 1.2 for up to 0.2 seconds, any per-unit voltage equal to or greater than 1.15 but less than 1.175 per unit voltage for up to 0.5 seconds, and any per-unit voltage equal to or greater than 1.1 but less than 1.15 for up to 1.0 seconds. The indicated voltages are measured at the POI.

(6) An IRR may be tripped Off-Line or curtailed after the fault clearing period if this action is part of an approved Remedial Action Schemes (RASs).

(7) VRT requirements may be met by the performance of the generators; by installing additional reactive equipment behind the POI; or by a combination of generator performance and additional equipment behind the POI. VRT requirements may be met by equipment outside the POI if documented in the SGIA.

(8) If an IRR fails to comply with the clearing time or recovery VRT requirement, then the IRR and the interconnecting TSP shall be required to investigate and report to ERCOT on the cause of the IRR trip, identifying a reasonable mitigation plan and timeline.



**Figure 1: Default Voltage Ride-Through Boundaries for IRRs.**

***3.2.3 Regulatory Required Incident and Disturbance Reports***

(1) In the event of a system incident or disturbance, as described by North American Electric Reliability Corporation (NERC) and the Department of Energy (DOE), QSEs, and TSPs or their Designated Agents shall provide required reports to ERCOT, the DOE and/or NERC. Types of incidents or disturbances which may trigger these reporting requirements are:

(a) Uncontrolled loss of Load;

(b) Load shed events;

(c) Public appeal for reduced use of electricity;

(d) Actual or suspected attacks on the transmission system;

(e) Vandalism;

(f) Actual or suspected cyber attacks;

(g) Fuel supply emergencies;

(h) Loss of electric service to large customers;

(i) Loss of bulk transmission component that significantly reduces integrity of the transmission system;

(j) Islanding of transmission system;

(k) Sustained voltage excursions;

(l) Major damage to power system components; and

(m) Failure, degradation or misoperation of Remedial Action Schemes (RASs) or other operating systems.

(2) Full descriptions of the DOE and NERC reports are available on their respective websites.

***4.3.1 Real-Time and Short Term Planning***

(1) ERCOT will conduct Real-Time and short term planning based on the security criteria established in these Operating Guides. Operations during Forced and Planned Outages will also follow these criteria. Line Ratings are provided to ERCOT in accordance with Protocols and these Operating Guides. ERCOT will employ Constraint Management Plans (CMPs) and use of Remedial Action Schemes (RASs) to facilitate the use of the ERCOT Transmission Grid while maintaining system security and reliability in accordance with the Protocols, these Operating Guides, and applicable North American Electric Reliability Corporation (NERC) Reliability Standards. ERCOT will address operating conditions under which the reliability of the ERCOT System is inadequate and no solution is readily apparent in accordance with the Protocols and these Operating Guides.

***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 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 and Texas RE, per the timeline established in paragraph (6) below or upon request. 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;

(c)

(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 and RAS misoperations reports shall be submitted to ERCOT 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, Data Recording Requirements.

**11. CONSTRAINT MANAGEMENT PLANS AND Remedial Action Schemes**

**11.1 Introduction**

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

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

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

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

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

(e) Mitigation Plans.

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

(3) Remedial Action Schemes (RASs) and/or Automatic Mitigation Plans (AMPs) may also be implemented in order to allow Generation Resources or Transmission Facilities that would otherwise be subject to restrictions to operate to their full Rating.

(4) ERCOT shall provide notification to the market of any approved, amended, or removed CMP or RAS. ERCOT shall provide notification to the market of any RAP, AMP, or RAS that cannot be modeled in the Network Operations Model. ERCOT shall post to the Market Information System (MIS) Secure Area all CMPs and RASs and any unmodeled CMPs or RASs.

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

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

(7) All submittals related to CMPs or RASs must be emailed to ras\_cmp@ercot.com.

**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.

(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 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 (SSR) 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 regulation (AVR) and power system stabilizers (PSS)], 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 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 RAS owner(s) shall coordinate the design and implementation of the RAS with the owners and operators of Facilities included in the RAS, including but not limited to Generation Resources, Transmission Service Providers (TSPs) and Direct Current Ties (DC Ties);

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

(d) The RAS shall not operate unnecessarily.

(e) To avoid unnecessary RAS operation, the RAS owner(s) may provide a Real-Time status indication to the owner of any Generation Resource 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 owner(s);

(f) 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;

(g) When an RAS is removed from service, the RAS owner(s) or a Designated Agent shall immediately notify ERCOT;

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

(i) The RAS owner(s) 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).

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

(4) The owner(s) of an existing, modified, or proposed RAS shall submit documentation of the RAS to ERCOT 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, AMPs, protection and control systems.

(a) ERCOT shall conduct a review of each proposed RAS, each proposed modification and proposed indefinite deactivation and/or termination of an existing RAS. Additionally, it shall conduct a review of each existing RAS at least every five years as required by changes in system conditions. . Upon receipt, ERCOT shall initiate a 30 working day review period to evaluate each proposal in accordance with paragraph (e) below. ERCOT shall coordinate any additional time needed for the evaluation with the RAS owner(s).

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 an RAS into service must be coordinated among ERCOT and the owners of the Facility controlled by the RAS, and shall provide sufficient time to perform any necessary functional testing prior to its being placed in service.

(e) ERCOT review of an RAS shall:

(i) Validate that RAS mitigates the system condition(s) or contingency(ies) for which it was designed;

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

(iii) Evaluate and demonstrate that the RAS shall be designed so that a single RAS component failure, when the RAS, was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in NERC Reliability Standards;

(iv) Evaluate and document the consequences of misoperation, incorrect operation, or unintended operation of an RAS, when considered by itself and without any other system contingency;

(v) Evaluate and demonstrate that proposed RAS will coordinate with other RASs, AMPs, protection and control systems and applicable Emergency procedures;

(vi) Evaluate future transmission project(s) that will eliminate the need for the RAS; and

(vii) Upon completion of ERCOT’s RAS review, ERCOT shall provide all results and underlying studies to the RAS owner(s).

(f) If deficiencies are identified by ERCOT or other parties’ comments, the RAS owner(s) shall either submit an amended RAS proposal or withdraw the RAS proposal. The amended RAS proposal shall undergo the review process specified in item (e) above using the timeline in item (a) above until the identified deficiencies have been resolved to the satisfaction of ERCOT.

(g) 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.

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

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

***11.2.1 Reporting of RAS Operations***

(1) RAS owner(s) 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. The RAS owner(s) shall conduct an analysis of all RAS operations, misoperations, and failures. If deficiencies are identified, a plan to correct the deficiencies shall be developed by the RAS owner(s) subject to the approval of ERCOT within 180 days of being identified and implemented by the RAS owner(s). 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 mitigation 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 Texas Reliability Entity (Texas RE) for review. RAS arming or activation that ramps generation back is not considered an operation or misoperation with respect to reporting requirements to the Texas RE. An operation and misoperation of an RAS with respect to reporting requirements to the Texas RE occurs when changes to the transmission system occur, including, but not limited to circuit breaker operation. Owners of RASs will provide a monthly report to ERCOT by the 15th of each month describing each instance an 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 Texas RE.

(3) If an 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 Generation Resource owner(s) to decrease the available capability on the affected Generation Resource(s). The amount of available capacity to be decreased shall be determined by ERCOT. The decreased available capacity on the Generation Resource(s) shall remain until the Generation Resource owner(s) provides documentation that demonstrates the Generation Resource(s) can properly control output in a pre-contingency or normal ERCOT System condition.

(4) For each RAS, the owner(s) shall either identify a preferred exit strategy or explain why no exit strategy is needed to ERCOT. Once an exit strategy is complete and a RAS is no longer needed, the owner(s) of an existing RAS shall notify ERCOT, whenever the RAS is to be permanently disabled, and shall do so according to a timetable coordinated with and approved by ERCOT and the owners of all Facilities controlled by the RAS.

**11.3 Automatic Mitigation Plans**

(1) Automatic Mitigation Plans (AMPs) are defined in Protocol Section 2.1, Definitions, and may be relied upon to detect predetermined abnormal system conditions and automatically take pre-coordinated corrective actions to maintain a secure system.

(2) AMPs must:

(a) Be proposed by a TSP or Resource Entity, and be approved by ERCOT and the TSP(s) and/or Resource Entity(ies) included in the AMP prior to implementation;

(b) Be designed and implemented in coordination with the owners and operators of Facilities included in the AMP and approved by ERCOT;

(c) Be automatically armed when appropriate;

(d) Not operate unnecessarily;

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

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

(3) AMP Owner(s) or a Designated Agent shall:

(a) Immediately notify ERCOT, when an AMP is removed from service and when an AMP is returned to service. ERCOT shall modify its reliability constraints to recognize the availability of the AMP;

(b) 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 AMP;

(ii) In-service/out-of-service status of the AMP; and

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

(c) Provide the status indication of any automatic or manual arming/activation or operation of the AMP as Supervisory Control and Data Acquisition (SCADA) alarm inputs to the owner(s) of any Facility controlled by the AMP;

(d) Submit documentation when proposing or modifying and/or deactivating/terminating an AMP that detail its design, operation and coordination of the AMP with other RASs, AMPs, protection and control systems.

(5) ERCOT shall conduct a review of each proposed AMP, each proposed modification and proposed indefinite deactivation and/or termination of an existing AMP. Additionally, ERCOT shall conduct a review of each existing AMP annually or as required by changes in system conditions to ensure its continued effectiveness.

**11.4 Remedial Action Plan**

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

(2) RAPs must:

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

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

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

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

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

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

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

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

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

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

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

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

**11.5 Mitigation Plan**

(1) Mitigation Plans are defined in Protocol Section 2.1, Definitions, and shall not be used to manage constraints in Security-Constrained Economic Dispatch (SCED). Normally, it is desirable that a Transmission Service Provider (TSP) constructs Transmission Facilities adequate to eliminate the need for a Mitigation Plan; however, in some circumstances, such construction may be unachievable in the available time frame.

(2) A Mitigation Plan may be proposed by any TSP, and be approved by ERCOT and the included Transmission Operator (TO) prior to implementation. Mitigation Plans must:

(a) Be coordinated with the TOs included in the Mitigation Plan;

(b) Limited in use to the time required to construct replacement Transmission Facilities; however, the Mitigation Plan will remain in effect if ERCOT has determined the replacement Transmission Facilities to be impractical;

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

(d) Clearly define and document TO actions;

(e) Be executed by TOs;

(f) Be able to be implemented in a timeframe that will not result in loss of the overloaded Transmission Facility;

(g) Identify the most limiting protective relay setting beyond the 15-Minute Rating when developing the Mitigation Plan in advance or as soon as practicable when developing the Mitigation Plan in Real-Time;

(h) Not subject ERCOT to unacceptable risk of widespread cascading Outages; and

(i) Not include generation re-Dispatch.

(3) An approved Mitigation Plan may be executed immediately, post-contingency, by the TO without instruction by ERCOT or shall be executed upon direction by ERCOT.

(4) Restoration of any Load shed by executing the Mitigation Plan shall be coordinated with ERCOT.

**11.6 Pre-Contingency Action Plans**

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

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

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

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

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

(d) Clearly define and document TO actions;

(e) Be executed by TOs; and

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

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

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

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

**11.7 Temporary Outage Action Plan**

(1) Temporary Outage Action Plans (TOAPs) are defined in Protocol Section 2.1, Definitions, and shall not be used to manage constraints in Security-Constrained Economic Dispatch (SCED).

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

(a) Be coordinated with the Transmission Operators (TOs) included in the TOAP;

(b) Limit use to the duration of a specific Transmission Facility or Resource Outage;

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

(d) Clearly define and document TO actions;

(e) Be executed by TOs;

(f) Be implemented in a timeframe that will not result in loss of the overloaded Transmission Facility;

(g) Identify the most limiting protective relay setting beyond the 15-Minute Rating when developing the TOAP in advance or as soon as practicable when developing the TOAP in Real-Time; and

(h) Not subject ERCOT to unacceptable risk of widespread cascading Outages; and

(i) Not include generation re-Dispatch.

(3) An approved TOAP may be executed immediately, post-contingency, by the TO without instruction by ERCOT or shall be executed upon direction by ERCOT.

(4) ERCOT may limit the quantity of TOAPs that are used.

(5) Restoration of any Load shed by executing the TOAP shall be coordinated with ERCOT.

**ERCOT Nodal Operating Guides**

**Section 8**

**Attachment K**

**Remedial Action Scheme (RAS) Template**

This attachment provides a template to be used by an entity for the proposal, modification or deactivations and/or retirement of a Remedial Action Scheme (RAS). All submittals related to RAS must be emailed to ras\_cmp@ercot.com.

1. **Overview**
	1. **Background**

*Describe the purpose for the RAS and/or triggering circumstances.*

* 1. **Drivers & Purpose**

*Describe ERCOT System performance criteria violation necessitating the RAS that are driving the need for this RAS. (e.g., thermal overload, angular instability, poor oscillation damping, voltage instability, under‐ or over‐ voltage, or slow voltage recovery).*

* 1. **Description**

*Describe the RAS in detail.*

* 1. **Anticipated Benefits**

*Provide high-level expected benefits and/or desired outcome due to implementation of this RAS.*

* 1. **Owner(s) & Affected Entity**

*List the owner(s) of the RAS and identify any* *owners and operators of Facilities included in the RAS, including but not limited to Generation Resources, Transmission Service Providers (TSPs) and Direct Current Ties (DC Ties).*

* 1. **Tentative Implementation Date**

*Provide the tentative implementation of this RAS (a general timeframe).*

* 1. **Exit Strategy**

*Provide information regarding any future transmission project(s) that will eliminate the need for this RAS. Have these projects been submitted for RPG review?*

1. **RAS Design**
	1. **Functional Overview**

*Describe functional operation of the RAS. Use logic diagram, flow chart, or truth table to document the RAS logic and illustrate how its functional operation is accomplished, where practicable. Is the RAS logic is event-based, parameter-based, or a combination?*

* 1. **Monitored Elements**

*Identify the element(s) that will be monitored by the proposed RAS. Example.*

* Line 1
* Transformer 1
* Switch
* Etc.
	1. **Arming Criteria**

*Describe the conditions under which the RAS is armed (e.g., always armed, armed for certain system conditions, actuation thresholds). If required, can the RAS be armed manually as well? Describe the arming criteria for RAS – analog quantities and/or equipment status monitored to determine existence of the system condition for which SPS is armed (e.g., generation/load patterns, reactive power reserves, facility loading) - May use in tabular format (example below).*

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Monitored Element** | **Element Type** | **Monitored Quantity (Flow / Status)** | **Dynamically Rated? (Yes/No)** | **Arming Threshold** | **Reset Threshold** |
|  |  |  |  |  |  |

* 1. **Action Taken**

*Once the RAS is armed, describe the actions that will be taken (for example: transmission facilities switched in or out; generators tripped or runback; load dropped. Also provide, time to operate each action, including intentional time delays (e.g., timer settings) and inherent delays (e.g., relay operating time). Describe the conditions when the RAS will be disarmed and/or reset.*

* 1. **Monitoring**

*Describe the telemetry (in-service/out-of-service, armed/activated, etc.) that will be available to monitor the status of the RAS. Nodal Operating Guide Section 11.2(2)(g) provide guides into expected RAS telemetry.*

* 1. **Redundancy**

*Provide details included in RAS design that ensure single component failure during instances when RAS is intended to operate do not result in misoperation.*

1. **Study/Analysis Performed**
	1. **Cases Used**

*List the cases used to study the effectiveness of the RAS Example*

* *SSWG Summer Peak case for the year 20XX (if used)*
* *Operations case for the year 20XX (If used)*
	1. **Case Modifications**

*List any modifications made to the study cases. Example.*

* *Modification 1 - Changes to generation and/or wind dispatch*
* *Modification 2 - changes to reactive power availability via cap banks*
* *OUTAGE 1 - Outages Applied, etc.*
	1. **Contingency List**

*List the contingencies (if any) that were used for the study.*

* 1. **Study Performed**

*Describe the technical study(s) that were performed. Example N-1 AC Contingency Analysis*

* 1. **Coordination**

*Describe the analysis conducted to ensure that the RAS settings and operation avoid adverse interaction with other RAS, protection and control systems and applicable Emergency procedures. If practicable provide the settings for the most limiting protective relay that could pick-up & respond to the trigger conditions of this RAS.*

* 1. **Inadvertent Operation/Misoperation**

*Describe the system performance resulting from the possible inadvertent operation and/or misoperation of the RAS.*

* 1. **Results**

*Summarize the important observations of the study – Identify any conditions that trigger the RAS & identify pre/post RAS activation flows.*

1. **Functional Testing**

*Describe the functional testing process/procedures that will be adopted to test that the RAS performs as designed and does not adversely impact other RAS or protective equipment.* *Include discussion of any coordination made with other entities, such as resources, plant owners, and generator representatives as applicable.*

1. **Conclusion**

*Present concluding remarks on the analysis performed and/or effectiveness of the proposed RAS.*