## REVISIONS

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1. Glossary
2. Introduction

The Operating Criteria contained within this document serve to support the values and principles upon which SPP is formed. These criteria are reviewed and managed by the Organizational Group structure as described in the SPP Bylaws. Unless stated otherwise in the applicable section of this document, these Operating Criteria shall be reviewed by the Operating Reliability Working Group (ORWG) and any revisions to this document shall be performed pursuant to the approved Revision Request Process and submitted to the Markets and Operations Policy Committee (MOPC) for consideration of approval. The MOPC shall present applicable Revision Requests to the SPP Board of Directors for their review and approval as appropriate.

2.1 Purpose

The Operating Criteria developed by SPP provide background information, guidelines, business rules, and processes for the operation and administration of the various SPP Operational and Operating Reliability Functions.

2.2 Document Relationship

The Operating Criteria developed by SPP provide background information, guidelines, business rules, and processes for the operation and administration of the various SPP Operational and Operating Reliability Functions.
3. Operating Functions Overview

SPP’s Operating Reliability Functions include: Reliability Coordination, Balancing Authority, Transmission Service Provider, and Reserve Sharing Group Administrator.

3.1 Reliability Coordination

Southwest Power Pool, Inc. is registered with the North American Electric Reliability Corporation (NERC) as a Reliability Coordinator (RC) for Transmission Operators (TOP’s), Generator Operators (GOP’s) and Balancing Authorities (BA’s). An RC has the highest responsibility and authority to act and direct actions in accordance with relevant NERC Reliability Standards and other directives put forth from the NERC or the Federal Energy Regulatory Commission (FERC) to preserve the integrity of the Bulk Electric System.

3.2 Balancing Authority

SPP also functions as a registered Balancing Authority for selected TOP’s and GOP’s. A Balancing Authority is a responsibility entity that integrates resource plans ahead of time, maintains load-interchange-generation balancing within the Balancing Authority Area, and supports Interconnection Frequency in real time. SPP’s Integrated Marketplace supports the Balancing Authority function of SPP.

3.3 Transmission Service Provider

SPP is also the Transmission Service Provider for the SPP Open Access Transmission Tariff. SPP administers the provisions of the Tariff and provides Transmission Service to Transmission Customers under the applicable transmission service agreements.

3.4 Reserve Sharing Group

SPP is registered with NERC as the Reserve Sharing Group (RSG). An RSG is a relationship established by contract between two or more BA’s that collectively maintain, allocate, and supply Operating Reserves required for each member BA’s use in recovering from contingencies within the group. The end result is that a lesser amount of Operating Reserves is maintained among the RSG members than would be required in the absence of the RSG. NERC Reliability Standards set forth requirements for how the RSG functions and what objectives RSGs must meet to maintain Bulk Electric System reliability.
As the administrator of the SPP RSG, and in coordination with other participating BAs, SPP maintains the *SPP Reserve Sharing Group Operating Process* that establishes standard terminology and minimum requirements governing the amount and availability of Contingency Reserves to be maintained by the distribution of Operating Reserve responsibility among members of the RSG. BAs participating in the SPP RSG shall meet the requirements set forth in the *SPP Reserve Sharing Group Operating Process*, which can be found on SPP.org at Documents-Governing.

4. **Reliability Coordination**

Continuous coordinated operation of the bulk electric system is essential to maintain reliable electric service to all customers. Reliability coordination procedures are established herein for sharing of operating information and around-the-clock coordination of normal and emergency operating conditions to secure the reliability of the bulk electric system.

4.1 **Responsibility and Authority**

The Reliability Coordinator has the responsibility and authority to take whatever actions are needed to ensure the reliability of its respective area and shall exercise that authority to alleviate capacity and energy emergencies and coordinate restoration activities between individual Transmission Operators. The Reliability Coordinator also shall have clear decision-making authority to act and to direct actions to be taken by Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities within its Reliability Coordinator Area to preserve the integrity and reliability of the Bulk Electric System. These actions shall be taken without delay, but no longer than 30 minutes, unless such actions would violate safety, equipment, or regulatory or statutory requirements. Under these circumstances, the Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, Load-Serving Entity, or Purchasing-Selling Entity shall immediately inform the Reliability Coordinator of the inability to perform the directive so that the Reliability Coordinator may implement alternate remedial actions.
4.1.1 Information and Data Exchange

4.1.1.1 Required Data Specification for the SPP Reliability Coordinator and the SPP Balancing Authority

The SPP Reliability Coordinator and the SPP Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions, Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The SPP Reliability Coordinator and the SPP Balancing Authority shall distribute its data specification to entities that have data required by the SPP Reliability Coordinator’s and the SPP Balancing Authority’s analysis functions, Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The entities shall satisfy the requirements contained within the “Required Data Specification for the SPP Reliability Coordinator and the SPP Balancing Authority” (RDS). SPP shall be responsible for maintaining the RDS. The Operating Reliability Working Group (ORWG) shall be responsible for initially approving the RDS and reviewing and approving subsequent changes to the RDS. The Reliability Compliance Working Group (RCWG) shall provide formal comments on proposed changes to the RDS prior to ORWG review. SPP shall distribute this document directly to each applicable entity both upon the initial approval and the approval of subsequent changes within 30 days.

4.1.1.2 SPP Sharing of Externally Provided Data

The SPP Reliability Coordinator shall obtain a current signed NERC Confidentiality Agreement from entities receiving data provided to SPP by an entity other than SPP ensuring that the confidentiality of the data be maintained as required by the NERC Confidentiality Agreement.

4.1.1.3 Node Connectivity Requirement (Effective Until 1/1/2018)

SPP operates ICCP nodes at both the primary and disaster recovery (backup) sites. Both the primary and backup site ICCP servers feed real-time data to the primary and backup site Energy Management Systems. To ensure maximum availability of ICCP data required for operating reliability, the following connectivity requirements are required:

- SPP members are required to configure their ICCP servers to connect to the SPP primary and backup sites concurrently and to make the same Block 1 and Block 2 data available to both nodes.
• SPP will normally reference the same ICCP Object ID from both nodes when reading member data, thus imposing no additional maintenance workload upon the member companies.

• Members operating a backup site may choose to concurrently serve data from that site. In that instance, SPP will configure the SPP primary ICCP node to communicate with the member’s primary site node and will configure the SPP backup site ICCP node to communicate with the member backup site node.

• SPP will configure the SPP backup site ICCP nodes to serve data to member sites using a separate and distinct ICCP Object ID in order to permit them to concurrently read operating reliability data from redundant nodes.

4.1.1.4 Node Connectivity Requirement (Effective 1/1/2018)

SPP operates ICCP nodes at both the primary and backup sites. Both the primary and backup site ICCP node feed real-time data to their primary and backup site Energy Management Systems concurrently. To ensure maximum availability of ICCP data required for reliability, the following connectivity requirements are required for entities registered with NERC as a Generator Operator or Transmission Operator within the SPP Reliability Coordinator Area to be binding on January 1, 2018 or as otherwise consistent with waiver provisions outlined in the RDS:

• All Transmission Operators are required to configure their ICCP nodes to connect to the SPP primary and backup sites concurrently and to make the same Block 1 and Block 2 data available to both nodes.

• All Transmission Operators and Generator Operators are required to configure two ICCP nodes so that, in the event of a failure of their active ICCP node, their alternate ICCP node reconnects to SPP’s ICCP nodes within 240 seconds.
  o If the TOP or GOP has a third party contract for their ICCP connections, then the third party should be able to reconnect within 240 seconds.

• All Generator Operators with more than 1500 MW of net aggregate generation or fifteen capacity resources in the SPP Balancing Authority Area are required to configure two ICCP nodes to read their Integrated Marketplace resource set point instructions from both SPP’s primary and secondary ICCP nodes concurrently.

In the event of an outage on ICCP Nodes:
• Planned maintenance outages should comply with the Outage Scheduling Information of the RDS (Telemetering and Control System Status). For forced or unplanned outages, the TOP or GOP should contact SPP and follow the Outage Scheduling Information of the RDS (Telemetering and Control System Status).

### 4.1.1.5 Synchrophasor Data Communication System – Phase I

Synchrophasor technology enables greater visibility into grid conditions by detecting and recording events that SCADA data may miss. SPP's Synchrophasor System allows SPP to collect, analyze, and archive time-synchronized data from phasor measurement units (PMU) or other phasor measurement recording devices with similar capabilities. SPP is focused on creating a more reliable electric grid by using PMU data to gain a better understanding of the dynamic nature of the grid resulting in increased model accuracy that enables reliable and efficient use of the existing transmission assets.

In Phase I of SPP’s Synchrophasor System project, the PMU devices and the associated data will be used to (a) analyze oscillation modes in the region, (b) analyze and benchmark voltage stability assessments against actual recorded data, (c) record phase angle differences to understand transmission system stress from a wide-area overview, (d) perform model validation for operations and planning system stability studies, and (e) provide enhanced insight while researching grid events in post-event analysis. Any change in use may introduce compliance impacts for member companies. The PMU devices and associated data in the SPP Synchrophasor System will not be used for any of the following purposes:

• Operational Planning Analysis;
• Real-time Assessments; or
• Real-time monitoring for purposes of making operational decisions within a 15 minute time horizon.

Prior to implementing subsequent phases of the Synchrophasor System project, this section shall be updated. If SPP relies on the PMU devices for purposes of control and monitoring, it will notify SPP member companies in adherence to CIP-002-5, Attachment 1 Criteria.

### 4.1.2 Member Responsibilities

Transmission Operators shall determine System Operating Limits (SOLs), as defined by NERC, in conjunction with transmission owners. SOLs will be provided for facilities that comprise flowgates and any other facilities as determined by the Transmission Operator in conjunction
with the transmission owners. The Transmission Operator shall inform the Reliability Coordinator of changes to any SOL as specified in Appendix OP-1 and notify the Reliability Coordinator of any SOL exceedances. The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with the SOL Methodology in SPP Planning Criteria 7.3.

4.1.2.1 Outage Reporting and Coordination

Each Transmission Operator, Generator Operator and Balancing Authority shall perform the functions specified in OP-2 Outage Coordination Methodology.

4.1.2.1.1 Special Protection Systems

The Transmission Operator shall immediately inform the Reliability Coordinator of the status of any Special Protection System, that may have an inter-Balancing Authority, or inter-Transmission Operator impact, including any degradation or potential failure to operate as expected.

4.1.2.1.2 Other Protection Systems

If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify the Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.

4.1.2.1.3 Fuel Supply

Balancing Authorities or Generator Operators, as appropriate, shall notify SPP of any generation derates resulting from Operational Flow Orders (OFOs) or Critical Notices or any other type of fuel delivery constraint. The parties submitting the information shall indicate that the derate is a result of an OFO, Critical Notices, or fuel delivery constraint and indicate which pipeline(s) or delivery constraints are impacting them. Whenever an OFO, Critical Notices, or fuel delivery constraint causes an inability for the Generator Operator to meet its firm obligations, it must use the normal established communication protocols to notify its host Balancing Authority. Furthermore, Balancing Authorities shall notify the SPP Reliability Coordinator should it be necessary to request a NERC Energy Emergency Alert and/or a SPP Other Extreme Conditions as a result of the OFO or Critical Notice.
4.1.2.2 Vegetation Management

This section of the SPP Criteria is applicable to all entities in the SPP Regional Entity footprint and the SPP Reliability Coordinator footprint. For the purpose of this Criteria and NERC Reliability Standard FAC-003, the SPP Regional Entity [SPP RE], the SPP Reliability Coordinator and the SPP Operating Reliability Working Group are collaborating to act as the Regional Reliability Organization [RRO] as identified in the Standard. NERC Reliability Standard FAC-003 requires a vegetation management program for ‘transmission lines operating at 200kV and above and to any lower voltage lines designated by the RRO as critical to the reliability of the electric system in the region’ (applicable lines). For the purpose of implementing FAC-003-1 and proposed revisions to the FAC-003 standard, the SPP RC will designate the applicable facilities that are to be monitored for compliance to the standard in consultation with the SPP ORWG. The SPP Reliability Coordinator designates the following transmission lines as being subject to the FAC-003 standard:

1. All transmission lines operating at 200kV and above; and
2. All transmission lines, not included in 1. above that are listed as monitored or contingent elements of an Interconnection Reliability Operating Limit (IROL) flowgate as published in the SPP IROL Relief Guides.

The SPP Reliability Coordinator develops and identifies IROL flowgates on a continual basis to ensure reliability. However, IROL flowgate facilities will only be added to the applicable lines list annually to provide adequate time for Transmission Owners to incorporate those facilities into their Transmission Vegetation Management Plans. The SPP Reliability Coordinator will maintain the master list of the applicable transmission lines. The facilities identified will become applicable to the standard 12 months after being identified by the RC. The SPP RC is responsible for communicating to the appropriate Transmission Owners those transmission lines designated as applicable transmission lines by the SPP RC and subject to compliance monitoring and reporting of vegetation contacts as detailed in NERC Reliability Standard FAC-003. The Transmission Owner shall develop communications and notification protocols for the purposes of implementing changes to the applicable transmission line list and for reporting vegetation contacts to the SPP RE.

4.1.2.3 Transmission Facility Ratings

Each Transmission Owner shall provide the SPP Reliability Coordinator with Normal and Emergency Ratings in accordance with the Transmission Owner’s Facility Rating methodology. Emergency Ratings are helpful in real-time operations, providing system operators a specified
time to implement mitigating actions before exceeding pre-contingent or post-contingent System Operating Limits. Transmission Owners shall provide the SPP Reliability Coordinator with the highest available Emergency Rating that provides sufficient time for system operators to take actions that are intended to keep actual loading within applicable limits. The SPP Reliability Coordinator will initiate mitigation procedures with the default assumption that the Emergency Ratings are associated with a finite time period of at least thirty minutes. For an Emergency Rating associated with a finite time period of less than thirty minutes, an approved operating guide must be on file with the SPP Reliability Coordinator. The operating guide must outline the steps that will be taken to reduce loading on the transmission facility within the finite time associated with the Emergency Rating.

4.1.3 Operating Reliability Working Group

The Operating Reliability Working Group shall be responsible for policy oversight of implementation and on-going reliability coordination processes and services as described in this Criteria. This working group shall make regular reports to the Markets and Operations Policy Committee.

4.1.4 SPP Staff

The SPP Staff shall be responsible for development and administration of reliability coordination processes and services as described in this Criteria, including budgeting and staffing requirements.

4.1.5 Reliability Coordinator Responsibilities

The SPP Reliability Coordinator shall be responsible for the following activities:

4.1.5.1 Reliability Assessments

(1) Monitor the collection of real-time operating information, schedules and daily forecasts from Balancing Authorities as specified in Appendix OP-1.

(2) Develop and use operational models to ensure that the Bulk Electric System can be operated reliably in anticipated normal and Contingency event conditions. The Reliability Coordinator shall conduct Contingency analysis studies to identify potential interface and other SOL and IROL exceedances, including overloaded transmission lines and transformers, voltage and stability limits, and determining the adequacy of operating reserve for the current operating day and the next day.
(3) Perform Day Ahead Contingency Analysis to assess the impact of any single transmission contingency 100kV and above while monitoring all facilities 100kV and above within the entire SPP RC Footprint and neighboring Balancing Authority Areas or Transmission Operators systems.

(4) Develop mitigation plans or operating guides for any potential interface, SOLs or IROLs found in the Day Ahead Contingency Analysis that is forecast to exceed 100% of the emergency rating of any facility 100kV and above or any pre-contingent bus voltages of +/- 5% and/or post-contingent bus voltages in excess of +/- 10%.

(5) During conditions where system reliability is threatened, notify and coordinate with affected Transmission Operators, Balancing Authorities, or Transmission Service Providers in determining appropriate control action.

(6) Perform voltage stability simulations for identified areas and paths with the potential for post contingent and real-time voltage stability issues. See Appendix OP-3.

(7) Sharing the results of its system studies, when conditions warrant or upon request, with other Reliability Coordinators and with Transmission Operators, Balancing Authorities, and Transmission Service Providers within its Reliability Coordinator Area. The Reliability Coordinator shall make study results available no later than 1500 Central Standard Time.

4.1.5.2 Operational Coordination

(1) Coordinate and grant permission for bulk transmission equipment maintenance.

(2) Coordinate pending generator maintenance.

(3) Manage the SPP Open Access Same-Time Information System (OASIS) node and Available Transfer Capability (ATC) calculation.

(4) Monitor the NERC Hot line and NERC Reliability Coordinator Information System (RCIS) and disseminating information.

(5) Initiating time error corrections (TEC).

(6) Initiating Geo-magnetic Disturbance (GMD) notifications and assist as needed in the development of any required response plans.

(7) in conjunction with its Transmission Operators and Balancing Authorities, develop action plans that may be required, including reconfiguration of the transmission system, re-dispatching of generation, reduction or curtailment of Interchange Transactions, or reducing load to return transmission loading to within acceptable SOLs or IROLs, and/or mitigate CPS or DCS exceedances.
4.1.5.3 Monitoring

(1) Monitor system frequency and its Balancing Authorities’ performance and direct any necessary rebalancing to return to CPS and DCS compliance. The Transmission Operators and Balancing Authorities shall utilize all resources, including firm load shedding, as directed by its Reliability Coordinator to relieve the emergent condition.

(2) Identifying sources of large Area Control Errors that may be contributing to Frequency Error, Time Error, or Inadvertent Interchange and shall discuss corrective actions with the appropriate Balancing Authority. The Reliability Coordinator shall direct its Balancing Authority to comply with CPS and DCS.

(3) Monitor Special Protection Systems that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL exceedance) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected.

(4) Monitor applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources.

(5) Coordinate bilateral inadvertent energy accounting and payback.

4.1.5.4 Emergency Procedure Implementation

(1) Monitor and coordinate implementation of Operating Reserve Criteria.

(2) Monitor and coordinate implementation of Transmission Loading Relief and other congestion management procedures.

(3) Monitor and coordinate implementation of Load Shedding and Restoration Criteria.

(4) Monitor and coordinate implementation of Black Start Criteria.

(5) Issue short supply advisories.

(6) Issue weather advisories.

(7) Evaluate actions taken to address an IROL or SOL exceedance and, if the actions taken are not appropriate or sufficient, direct actions required to return the system to within limits.

4.1.5.5 Interregional Coordination

(1) Coordinate normal and emergency operations with other Reliability Coordinators.
(2) Authoritatively act on behalf of SPP Members to resolve interregional issues.

4.1.5.6 Other Reliability Coordinator Responsibilities

The SPP Reliability Coordinator shall be responsible for the following additional activities:

(1) Coordinate implementation of Black Start procedures as outlined in Criteria.
(2) Implement Transmission Loading Relief Procedures and other congestion management procedures as required.
(3) Administer the SPP Reserve Sharing Group.
(4) Provide reports to the ORWG of congestion management activities performed by the RC. These reports shall also be posted periodically.

4.1.5.7 Reliability Coordinator Performance Standards

The SPP Reliability Coordinator shall have the following performance standards:

(1) The SPP Reliability Coordinator shall act in accordance with Good Utility Practice including NERC Standards and SPP Criteria, shall not order SPP members to take any action that would not be in accordance with Good Utility Practice or NERC Standards, and shall allow SPP members to take any actions required by Good Utility Practice and NERC Standards.
(2) The SPP Reliability Coordinator shall not take any action, or direct SPP members to take any action, which would be in violation of any lawful regulation or requirement of any governmental agency or NERC Standard.
(3) The SPP Reliability Coordinator shall carry out its responsibilities in at least as prompt and efficient a manner as that required by Good Utility Practice including NERC Standards and SPP Criteria.
(4) The SPP Reliability Coordinator shall monitor adherence to its directives and report non-compliance to the appropriate SPP organizational group.
(5) The SPP Reliability Coordinator shall possess the applicable NERC Certification.
(6) The SPP Reliability Coordinator shall sign an appropriate standards of conduct document ensuring appropriate protection of competitively sensitive information.
5. Balancing Authority

6. Transmission Service Provider

8. Emergency Communication

Dependable communications are critical to maintaining the reliability of the Bulk Electric System. Accordingly, NERC has outlined necessary communication links in the reliability standards applying to Transmission Operators, Balancing Authorities, and Reliability Coordinators. It is vital that communication channels are functional and disturbances to the communication network should be addressed.

Key critical paths:

- Internal communications
- Between the Reliability Coordinator and its Transmission Operators and Balancing Authorities.
- With other Reliability Coordinators, Transmission Operators, and Balancing Authorities as necessary to maintain reliability.
- Where applicable, these facilities shall be redundant and diversely routed.

The communication paths should be verified periodically and an action plan should exist to maintain and recommend solutions to communication problems.

8.1 SPP Emergency Communication Network

The SPP Emergency Communication Network is comprised of Satellite Phones located at the SPP primary and backup control centers, control centers of each member Balancing Authority and/or Transmission Operator. If loss of any primary communication facilities are encountered, the SPP Emergency Communication Network shall be used to exchange information. Therefore, it is important for operators to be familiar and comfortable with the operation of the Satellite Phones. The Reliability Coordinator shall ensure proper training.

Balancing Authorities, Transmission Operators and Reliability Coordinators shall participate in weekly testing of the SPP Emergency Communication Network. Testing will ensure reliability
and it will also give users practice on the system. The Reliability Coordinator shall initiate and monitor the SPP Satellite Phone testing.

During actual emergency conditions requiring the use of the SPP Emergency Communication Network, the Reliability Coordinator shall initiate a Group Call and quickly determine the extent of the interruption. Communication is vital to an orderly recovery. Operating personnel shall keep conversations concise to keep channels clear. Priority should be given to establishing voice communication paths prior to re-establishing data communication paths.

### 8.2 Information Priority during Emergencies

System status conditions to be surveyed include but are not limited to the following items:

1. Areas of the electric system which are de-energized,
2. Areas of the electric system which are functioning,
3. Amount of generation and generating reserve available in functioning areas,
4. Power plant availability and time required to restart,
5. Status of transmission breakers and sectionalizing equipment along critical transmission corridors, and at power plants,
6. Status of transmission breakers and sectionalizing equipment at tie points to other areas,
7. Status of fuel supply from external suppliers,
8. Under-frequency relay operation,
9. Relay flags associated with circuits tripped by protective relays.
10. Status of communication systems.

* Refer to COM-001 and COM-002 for more information on maintaining reliable communications
Appendix OP-2: Outage Coordination Methodology

Purpose

The purpose of this methodology is to provide technical requirements and criteria to Transmission Operators, Generator Operators and SPP Staff related to submission of Transmission and Generation outages to the SPP Reliability Coordinator and SPP Balancing Authority via the SPP CROW tool. Outage submissions will be shared with other Reliability Coordinators, Transmission Operators, and Balancing Authorities via the NERC System Data Exchange (SDX) and will be used for assessing real-time and future reliability of the Bulk Electric System.

Transmission and generation operators are responsible for submitting all outages through the CROW tool. All other transmission operators will be able to view and identify all outages that are submitted through CROW. SPP reserves the right to approve, deny, or reschedule any outage deemed necessary to ensure system reliability on a case by case basis regardless of date of submission.

1. Transmission Outages and Operations

For the purpose of identifying applicable facilities, the nominal kV level of the facility will be used. For transformers, use the low side voltage class. Example: A 161/69kV transformer shall be classified as a 69kV facility for the purposes of this methodology.

a. Forced Transmission Outage Submission Requirements
Forced outages of all transmission facilities greater than 60kV that are modeled in the SPP regional models and have been modeled in the CROW tool should be submitted within 30 minutes or as soon as practical after the outage. Each outage submission must be accompanied by a Planned End Time, Forced Outage Priority, an associated Outage Request Type, and an Outage Cause. Forced Outage Priority outages will be considered Non-Recallable. At the time of submission, forced outage reasons may not be known so a reason of Unknown may be selected. It is recognized that the duration of a forced outage will typically not be known at the time of the initial submission. The Planned End Time should be the best estimate for the return of the outaged facility. Any known updates to the Planned End Time and/or reason for the outage shall be submitted promptly to the CROW tool.

b. Scheduled Transmission Outage Submission Requirements

Scheduled outages of all BES elements must be submitted to the CROW tool and approved by the Reliability Coordinator prior to implementing the outage. Scheduled outages of all other transmission elements greater than 60kV that are modeled in the SPP regional models must be submitted to the Reliability Coordinator’s CROW tool for coordination and review. Each outage submission must be accompanied by a Planned Outage Start Time and Planned End Time, Outage Priority, Outage Request Type, and Outage Cause. Each outage request must also be designated as Non-Recallable, or provide an expected Recall time if directed. Sufficient notation in the outage scheduler “Requestor Notes” comment field should include a description or explanation for the outage. An incomplete outage request of any missing data could result in the outage being denied. Once the actual outage takes place, the Actual Start Time of the outage must be submitted to the CROW tool. When the outage has ended, the Actual End Time of the outage must be updated.

c. Transmission Outage Priority and Timing Requirements

Each Transmission Outage submitted must include one of the following Outage Priorities. Forced outages of equipment must be submitted with a Priority of Forced as defined below. The CROW Outage Scheduler will enforce the lead time requirements of each Outage Priority. Outages that are not planned will have a lower priority and may not be approved by the RC. Outages not submitted as planned will be reviewed and approved by SPP on a case-by-case basis. The risk of imminent equipment failure will have priority over other outages including planned. If sufficient time is not available to analyze the request then the outage will be denied.

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<th>Priority</th>
<th>Definition</th>
<th>Minimum Lead Time</th>
<th>Maximum Lead Time</th>
</tr>
</thead>
<tbody>
<tr>
<td>Planned</td>
<td>Equipment is known to be operable with little risk of leading to a forced outage. As required for preventive maintenance, troubleshooting, repairs that are not viewed as urgent, system improvements such as capacity upgrades, the</td>
<td>14 Calendar Days</td>
<td>None</td>
</tr>
</tbody>
</table>
installation of additional facilities, or the replacement of equipment due to obsolescence.

| Discretionary | Equipment is known to be operable with little risk of leading to a forced outage; however the timeline for submission of Planned outage priority has passed. Discretionary outages are required to be submitted at least 2 calendar days in advance. Due to the shorter lead time, this outage priority has increased risk of being denied based upon higher priority outage requests. | 2 Days | 14 Calendar Days |
| Opportunistic | Lead time may be very short or zero. An outage that can be taken due to changed system conditions (ie Generator suddenly offline for forced outage allows transmission work to be done). | None | 7 Days |
| Operational | Equipment is removed from service for operational reasons such as voltage control, constraint mitigation as identified in an operating procedure, etc. | None | None |
| Urgent | Equipment is known to be operable, yet carries an increased risk of a forced outage or equipment loss. The equipment remains in service until maintenance crews are ready to perform the work. | 2 Hours | 48 Hours |
| Emergency | Equipment is to be removed from service by operator as soon as possible because of safety concerns or increased risk to grid security. | None | 2 Hours |
| Forced | Equipment is out of service at the time of the request. | None | 1 Hour |

d. Transmission Outage Equipment Request Types

Each Transmission outage (scheduled and forced) request submitted must include one of the following Outage Request Types.

<table>
<thead>
<tr>
<th>Outage Request Type</th>
<th>Definition</th>
<th>Modeling Assumptions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Out of Service (OOS)</td>
<td>Equipment is out of service.</td>
<td>SDX = Open</td>
</tr>
<tr>
<td></td>
<td></td>
<td>EMS = Open</td>
</tr>
<tr>
<td>Normally Open (NO)</td>
<td>Equipment is normally out of service and is identified as normally open in the SPP regional models. Normally Open request type is used to close (place in service) a normally open facility.</td>
<td>SDX = Closed</td>
</tr>
<tr>
<td></td>
<td></td>
<td>EMS = Closed</td>
</tr>
<tr>
<td>Informational (INF)</td>
<td>Used for outage events that are not covered by one of the other Outage Equipment Request Types. Not an out of service event.</td>
<td>None – Informational Only</td>
</tr>
<tr>
<td>Hot Line Work (HLW)</td>
<td>Work is being performed on live or energized equipment.</td>
<td>None – Informational Only</td>
</tr>
<tr>
<td>General System Protection (GSP)</td>
<td>Work is being performed on protection systems. Requestor shall specifically identify protection systems out of service and any modification to operation or behavior of system contingencies.</td>
<td>None – Informational Only</td>
</tr>
</tbody>
</table>

e. Transmission Outage Request Reasons/Causes

Each Transmission Outage Request must be submitted with one of the following reasons for the outage.

<table>
<thead>
<tr>
<th>Reason/Cause</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maintenance &amp; Construction</td>
<td>Outages to facilitate repair, maintain, or upgrade of facility related equipment. This includes clearances to perform vegetation management. Does not include outages to support Maintenance &amp; Construction of other facilities. Those should be submitted as Voltage or SOL Mitigation.</td>
</tr>
<tr>
<td>Third Party Request</td>
<td>Non-transmission facility related requests for clearance or work such as highway construction.</td>
</tr>
</tbody>
</table>
### Voltage Mitigation
Operation of facilities to preserve or correct Bulk Electric System voltage.

### SOL Mitigation (Thermal)
Operation of facilities to preserve or correct Bulk Electric System thermal loading issues.

### Weather/Environmental/Fire (excluding Lightning)
Outages caused by wind, ice, snow, fire, flood, etc. All weather or environmental causes excluding lightning strikes.

### Lightning
Outages caused by direct or indirect Lightning strikes.

### Foreign Interference (Including contamination)
Outages caused by blown debris, bird droppings, kites, falling conductors, airplanes, etc.

### Vandalism/Terrorism/Malicious Acts
Outages resulting from known or suspected vandalism, terrorism, or other malicious acts.

### Equipment Failure
Outages resulting from failure of facility related equipment.

### Imminent Equipment Failure
Operation of facilities due to expected imminent facility rated equipment failure.

### Protection System Failure including Undesired Operations
Operation of facilities due to failure or undesired operation of the facility protection systems.

### Vegetation
Outages resulting from contact with vegetation. This does not include outages due to clearances required to perform vegetation management which should be submitted as Maintenance & Construction. This does not include vegetation blown into rights of way or into contact with facilities which should be submitted as Foreign Interference.

### BES Condition (Stability, Loading)
Outages resulting from Bulk Electric System conditions such as islanding, cascading outages, sudden thermal loading due to other contingencies, transient stability conditions, etc.

### Unknown
Operation of facilities due to an unknown reason. Most forced outages will be submitted with an initial reason of Unknown. Once the actual reason for the operation is known, the outage requestor should update the outage request. SPP Staff will follow up after some time to determine the actual outage reason for any outages which still have a reason of Unknown submitted.

### Upcoming Model Change
Outages created for the purpose of correcting system topology related to pending model changes. This cause should only be used by SPP operations personnel.

### Other
Operation of facilities due to a reason not listed here.

## 2. Generation Outages/Derates

### a. Generation Outages/Derate Submission Requirements
All generating resources within the SPP Reliability Coordinator Area or Balancing Authority Area meeting one or more of the criteria listed below (regardless of voltage connection) shall report in CROW all Outages and Derates if the gross reduction in capability is greater than or equal to 25 MW. Changes to the reported capability shall be reported in 25 MW increments from the last reported Derate level regardless of system capability/conditions.

- Generating resource(s) with gross individual nameplate rating greater than 20 MVA or gross plant/facility aggregate nameplate rating greater than 25 MVA; or
- Blackstart Resources identified in a Transmission Operator’s restoration plan; or
- Dispersed power producing resources with aggregate capacity greater than 25 MVA (gross aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity.

If SPP requires generating resources that do not meet the criteria above to report their Outages and/or Derates in CROW, then SPP shall send a written notice to the responsible entity stating their obligations and identifying the specific generating resources.
For the generating resources under the functional control of a Generator Operator (GOP) registered with NERC, the GOP shall be the responsible entity for reporting Outages and Derates in CROW. For all other generating resources not under the functional control of a registered GOP, the resource owner shall be the responsible entity for reporting Outages and Derates in CROW.

b. **Forced Generation Outages/Derate Submission Requirements**

Forced outages or capability limitations in the form of Derates should be submitted within 30 minutes or as soon as practical after the outage or capability limitation occurs. Forced Generation Outages and Derates are required to be accompanied by a reason for the outage or limitation. Each Outage or Derate submission must be accompanied by a Planned End Time, a Forced Outage Priority, Outage Request Type, and an Outage Cause. Forced Outage Priority requests will be assumed to be Non-Recallable. At the time of submission, forced outage reasons may not be known so a reason of Unknown may be selected. The Planned Start Time of the outage should reflect the best known time of the actual outage. The CROW tool will ensure that the Actual Start Time and Planned Start Time are equal. Any known updates to the Planned End Time and/or reason for the outage shall be submitted promptly to the CROW tool. This outage submission shall be in addition to any other notifications made to SPP such as through a Reserve Sharing event, or Resource Plan submission. SPP shall accept each forced outage within 30 minutes of submission.

c. **Scheduled Generation Outages/Derate Submission Requirements**

Scheduled Outages or capability limitations in the form of Derates should be submitted as soon as possible and to the extent possible on an annual rolling basis. Planned Generation Outages are required to be accompanied by a reason for the outage or limitation. Each Outage or Derate submission must be accompanied by a Planned Outage Start Time and Planned End Time, an associated Outage Priority, an associated Outage Request Type, and an Outage Cause. Each outage request must also be designated as Non-Recallable, or provide an expected Recall time if directed. Once the actual outage takes place, the Actual Start Time of the outage must be submitted to the CROW tool. SPP shall respond to all scheduled outages or capacity limitation changes in the CROW system within 30 minutes from the time of submission for changes that are effective within the next 48 hours. When the outage has ended, the Actual End Time of the outage must be updated. This outage submission shall be in addition to any other notifications made to SPP such as through a Reserve Sharing event or Resource Plan submission.

1. **Reserve Shutdown**

Resources in SPP are considered to be in a Reserve Shutdown outage status when SPP has approved an outage request via the CROW tool, making the Resource unavailable for SPP
commitment and dispatch due to reasons other than to perform maintenance or to repair equipment. These resources will be reflected in Planned Outage for a reason of Excess Capacity/Economic.

Resources that are offline for economic or excess capacity reasons and can be recalled, started, and synchronized to pick up load within 7 days are not required to request an outage via the CROW tool. However, these Resources may request and be shown in Reserve Shutdown outage status if the outage is approved by SPP.

d. Generation Outage/Derate Priority and Timing Requirements

Each Generation Outage or Derate submitted must include one of the following Outage Priorities. Forced outages of equipment must be submitted with a Priority of Forced as defined below. The CROW tool will enforce the lead time requirements of each Outage Priority.

<table>
<thead>
<tr>
<th>Priority</th>
<th>Definition</th>
<th>Minimum Lead Time</th>
<th>Maximum Lead Time</th>
</tr>
</thead>
<tbody>
<tr>
<td>Planned</td>
<td>Equipment is known to be operable with little risk of leading to a forced outage. As required for preventive maintenance, troubleshooting, repairs that are not viewed as urgent, system improvements such as capacity upgrades, the installation of additional facilities, or the replacement of equipment due to obsolescence.</td>
<td>14 Calendar Days</td>
<td>None</td>
</tr>
<tr>
<td>Opportunity</td>
<td>Lead time may be very short or zero. An outage that can be taken due to changed system conditions (i.e., loading conditions allow planned work to occur with short lead time).</td>
<td>None</td>
<td>14 Calendar Days</td>
</tr>
<tr>
<td>Operational</td>
<td>Equipment is removed from service for operational reasons. This could include outages or derates due to reliability directives or other operational concerns not necessarily related to the generating equipment or capability, and outages entered to correct system topology in operating models.</td>
<td>None</td>
<td>None</td>
</tr>
<tr>
<td>Urgent</td>
<td>Equipment is known to be operable, yet carries an increased risk of a forced outage or equipment loss. The equipment remains in service until maintenance crews are ready to perform the work.</td>
<td>24 Hours</td>
<td>48 Hours</td>
</tr>
<tr>
<td>Emergency</td>
<td>Equipment is to be removed from service by operator as soon as possible because of safety concerns or increased risk to grid security.</td>
<td>None</td>
<td>24 Hours</td>
</tr>
<tr>
<td>Forced</td>
<td>Equipment is out of service at the time of the request.</td>
<td>None</td>
<td>1 Hour</td>
</tr>
</tbody>
</table>

e. Generation Outage/Derate Request Type

Each Generation outage or Derate request submitted must include one of the following Outage Request Types.

<table>
<thead>
<tr>
<th>Request Type</th>
<th>Definition</th>
<th>Modeling Assumption</th>
</tr>
</thead>
<tbody>
<tr>
<td>Out of Service</td>
<td>Generator or Resource is out of service.</td>
<td>SDX = offline</td>
</tr>
<tr>
<td>Reason/Cause</td>
<td>Definition</td>
<td></td>
</tr>
<tr>
<td>------------------------------</td>
<td>----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
<td></td>
</tr>
</tbody>
</table>
| EMS = offline                | SDX = online, with new lower PMAX  
EMS = online, with new lower PMAX |
| Derate                       | Generator or Resource maximum capability is lowered from normal operation. A new maximum capability is required to be submitted with each Outage Request Type of Derate.                                      |
| Informational (INF)          | Used for communicating and documenting information to SPP regarding the resource. This status is not interpreted as a loss of capability or capacity. This status may be used to communicate anticipated fuel delivery issues.                                |
| None – Informational Only    | None – Informational Only                                                                                      |

f. **Generation Outage/Derate Request Reasons/Causes**

Each Generation Outage or Derate Request must be submitted with one of the following reasons for the outage.

<table>
<thead>
<tr>
<th>Reason/Cause</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Equipment Failure</td>
<td>Failure in station generation, prime mover, or other equipment has occurred. Does not include failure of GSU transformers or interconnection facilities. Does include equipment related to fuel delivery considered a part of the resource (such as a coal mill).</td>
</tr>
<tr>
<td>Imminent Equipment Failure</td>
<td>Expected failure in station generation, prime mover, or other equipment. Does not include failure of GSU transformers or interconnection facilities. Does include equipment related to fuel delivery considered a part of the resource (such as a coal mill).</td>
</tr>
<tr>
<td>BES Reliability</td>
<td>Removal from service or limitation to preserve or correct Bulk Electric System reliability issues either through action of a Special Protection System, runback scheme, or as mitigation of another reliability event.</td>
</tr>
<tr>
<td>Loss of Interconnection</td>
<td>Failure in interconnection equipment such as GSU transformers or other interconnection facilities. Does not include loss of synchronization due to stability or islanding type events.</td>
</tr>
<tr>
<td>BES Stability</td>
<td>Removal from service or limitation due to Bulk Electric System stability issues. Includes loss of synchronization due to transient stability and/or islanding issues.</td>
</tr>
<tr>
<td>Fuel Supply</td>
<td>Removal from service or limitation due to fuel supply interruption. Does not include local equipment failures related to fuel supply. Includes loss of gas pressure due to offsite issue, coal supply exhaustion, lack of headwater issues for hydro, etc.</td>
</tr>
<tr>
<td>Regulatory/Safety/Environmental</td>
<td>Removal from service or limitation due to Regulatory/Safety/Environmental restrictions such as emission limits, OSHA, NRC, or other regulatory body limitations. Includes damage caused by weather including but not limited to lightning, flood, earthquake, etc. This may also include limitations to hydro due to low dissolved oxygen in tailwater or to control downstream flooding.</td>
</tr>
<tr>
<td>Unknown</td>
<td>The default Forced Outage/Derate reason will be pre-populated with Unknown at the time of submittal. Either during the initial outage submittal or at a later time, the Unknown reason must be changed to reflect the actual experienced issue.</td>
</tr>
<tr>
<td>Routine Generator Maintenance</td>
<td>Removal from service or limitation in order to perform repair or inspection of generation equipment.</td>
</tr>
<tr>
<td>Supporting Transmission Outage</td>
<td>Removal from service or limitation in order to support a scheduled transmission outage.</td>
</tr>
<tr>
<td>Excess Capacity/Economic</td>
<td>Removal from service or limitation due to seasonal or system capacity need. This includes peaker units not expected to be used during winter months.</td>
</tr>
<tr>
<td>Upcoming Model Change</td>
<td>Outages created for the purpose of correcting system topology related to pending model changes. This cause should only be used by SPP operations personnel.</td>
</tr>
</tbody>
</table>
3. **Outage Review / Approval Process**

All outages submitted will be studied to determine if any potential reliability conflicts are found. The general study method employed by SPP staff involves building representative models of the study time period and implementing all outage requests submitted for that time period. The resulting modeled system is then studied to determine if any reliability issues can be identified. If issues are identified, various mitigation steps are then studied including but not limited to, generation redispatch, system reconfiguration, rescheduling of lower priority outages, and facility rating reviews. If mitigations are unsuccessful in resolving the conflict, an outage request may need to be rescheduled or denied. Priority of outage requests is reviewed based upon initial submission time, outage priority category, reason for the outage, and impact to reliability. To the extent possible, higher priority category requests will be given preference, but ultimately it is up to the SPP RC to resolve any scheduling conflicts.

In the event that a conflict occurs with another Reliability Coordinator’s outage, a priority of the outages will be determined based on submitted time, reason for outage, and impact to reliability. The determination will be reviewed and agreed upon by each Reliability Coordinator. The outage that is deemed a higher priority will be approved.

An outage that has been studied will receive a status change to one of the following statuses: Approved, Denied, or Pre-Approved. Pre-Approval will be provided in certain cases where an outage has been submitted, but for various reasons SPP is unable to adequately study the outage or determine that no reliability conflicts exist. The Pre-Approval may also be dependent upon a specific operating condition that may need to be met but cannot be guaranteed at the time the Pre-Approval is issued such as but not limited to a load forecast threshold, simultaneous outage, new facilities in-service, etc. When the outage request can be adequately studied to determine that no reliability conflict exists, the status will be changed to Approved.

All outages submitted within the appropriate advance timeframe will be reviewed as soon as possible by SPP Operations Staff. The review timelines for SPP are as follows:

a. **Transmission**
   1. For all BES outage requests submitted 30 days or more prior to scheduled start time, Pre-approval or denial will be provided within 5 business days.
   2. For all BES outage requests submitted 14 days or more but less than 30 days prior to the scheduled start time, pre-approval or denial will be provided within 3 business days.
   3. For all BES outage requests submitted 14 days or less prior to scheduled start time, pre-approval or denial will be provided within 2 business days.

b. **Generators**
1. For all Generator outage requests submitted 30 days or more prior to scheduled start time, Pre-approval or denial will be provided within 5 business days.

2. For all Generator outage requests submitted 14 days or more but less than 30 days prior to the scheduled start time, Approval, Pre-approval or denial will be provided within 3 business days.

3. For all Generator outage requests submitted 14 days or less prior to scheduled start time, Approval, Pre-approval or denial will be provided within 2 business days.

4. SPP will provide their best effort for outages submitted within 2 business days.

4. **Outage Status Changes**

All outages submitted will reside in one of several status types throughout the life cycle of the outage. These status types and their associated definition are:

<table>
<thead>
<tr>
<th>Status</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Proposed</td>
<td>The outage request has been saved in the CROW tool and remains under the full revision control until the outage is entered into a Submitted state by the requestor. If the requestor does not move a proposed request to the submitted status within 30 days of the planned start date, the outage is automatically Withdrawn. Proposed outage request status dates DO NOT qualify for outage queuing in conflict resolution. Proposed outage requests are not provided to external systems such as NERC SDX/IDC or SPP’s EMS.</td>
</tr>
<tr>
<td>Submitted</td>
<td>The outage request has been submitted into the CROW tool and is ready for review by SPP. The outage requestor does not possess revision control of the outage in this status. A revision request may be submitted to SPP regarding an outage in Submitted status. Outage requests in this state are provided to external systems such as NERC SDX/IDC or SPP’s EMS.</td>
</tr>
<tr>
<td>Study</td>
<td>SPP will change the status type to Study once the active study process begins. Outage requests in this state are provided to external systems such as NERC SDX/IDC or SPP’s EMS.</td>
</tr>
<tr>
<td>Preliminary Approved</td>
<td>Outage requests with Preliminary Approved status have been approved based on long lead studies and may need additional analysis closer to the planned start date or finalization of an Operating Guide. Once the restudy is complete or final opguide posted, the outage status is changed to Approved. Outage requests in this state are provided to external systems such as NERC SDX/IDC or SPP’s EMS.</td>
</tr>
<tr>
<td>Approved</td>
<td>Approved state indicates SPP has completed the study process and the outage request is ready for implementation. Outage requests in this state are provided to external systems such as NERC SDX/IDC or SPP’s EMS.</td>
</tr>
<tr>
<td>Implemented</td>
<td>Once the outage request actual start time has been entered, signifying that the outage has begun, the outage status is changed to Implemented. Outage requests in this state are provided to external systems such as NERC SDX/IDC or SPP’s EMS.</td>
</tr>
<tr>
<td>Completed</td>
<td>Once the outage request actual end time has been entered, signifying that the outage has ended, the outage status is changed to Completed. Outage requests in this state are NO LONGER provided to external systems such as NERC SDX/IDC or SPP’s EMS.</td>
</tr>
</tbody>
</table>

Certain outage requests may result in a need by the outage requestor to withdraw or cancel the outage request. SPP’s study results and coordination may also result in status changes to an outage reflecting the inability of the outage request to be approved or implemented. These status types are:
### Status Definitions

<table>
<thead>
<tr>
<th>Status</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Withdrawn</td>
<td>The outage requestor can withdraw an outage request while it is still in Proposed status. Once in Study or Approved status, the request must be Cancelled. Outage requests in this state are NOT provided to external systems such as NERC SDX/IDC or SPP’s EMS.</td>
</tr>
<tr>
<td>Cancelled</td>
<td>The outage requestor can cancel a Submitted or Approved outage. Cancelled outages can be reinstated by the requestor, provided the planned start of the outage falls within the business rules for lead time submission. Outage requests in this state are NOT provided to external systems such as NERC SDX/IDC or SPP’s EMS.</td>
</tr>
<tr>
<td>Denied</td>
<td>An outage request that is in Submitted or Study status can be Denied. If SPP denies the request, the status changes to Denied. This state indicates the outage request was not approved for implementation. Outage requests in this state are NOT provided to external systems such as NERC SDX/IDC or SPP’s EMS.</td>
</tr>
<tr>
<td>Revoked</td>
<td>Once an outage request has been Approved, it can be Revoked at any time (i.e., before or during the outage). Outage requests in this state are NOT provided to external systems such as NERC SDX/IDC or SPP’s EMS.</td>
</tr>
</tbody>
</table>

### 5. Using CROW to Submit Other Types of Information to SPP

CROW can be used as a mechanism to submit information to SPP other than outage and or status information on lines, transformers, and generators. All other types of information exchange made using CROW not previously described in this Appendix 12 will follow the guidelines below.

For Reactor, Capacitor, Circuit Breaker, Disconnect, and Protection Scheme (Special Protection System) Equipment Types

- All CROW submissions for these equipment types will be made in accordance with Appendix 12 Sections 1d, 1e, and 1f
- Appendix 12 Section 3 Outage Review / Approval Process will not apply to these equipment types
- These equipment types will not progress through the various states described in Appendix 12 Section 4 Outage Status Changes

For Generator Automatic Voltage Regulator (AVR) and Power System Stabilizers Equipment Types

- All CROW submissions for this equipment type will be made in accordance with Appendix 12 Sections 2c, 2d, and 2e
- Appendix 12 Section 3 Outage Review / Approval Process will not apply to these equipment types
- These equipment types will not progress through the various statuses described in Appendix 12 Section 4 Outage Status Changes
Appendix OP-3: Voltage Stability Assessment and Monitoring Methodology

Change History:

| 4/27/2017 | Initial Version |

Purpose

The purpose of this methodology is to provide technical requirements and criteria to Transmission Operators, Generator Operators and SPP Staff related to the voltage stability assessment and monitoring of pre- and post-contingency (single and multiple) operating conditions. Monitored scenarios will be identified using available reliability studies, real-time system information, outage schedules, and other relevant sources. During the different Operating Horizons, the pre- and post-contingency operating conditions being studied may require adjustment. The SPP RC and TOPs must determine and coordinate which Multiple Contingencies within the TOP areas are credible to be utilized for study in the operating horizon.

If the TOP or the SPP RC determine that changes are required for a pre- or post-contingency operating condition, such changes shall be communicated to the affected entities. The SPP RC will coordinate with all applicable impacted TOPs or neighboring RCs.

The use of proxy flowgate limits for voltage stability will be communicated in the same manner as other flowgate limits and information.

1. Study Models
   a. SPP utilizes both the EMS model and the approved Planning Base Cases for establishing, calculating and monitoring SOLs/IROLs in the operating horizons. These cases are updated periodically to reflect expected system topology changes based on reported facility outages or upgrades.

2. Real Time and Post Contingent Voltage Stability Limits
   a. The SPP RC will perform a voltage stability assessment for identified areas and paths that have a reasonable potential to cause real-time and post-contingency voltage instability.
   b. The SPP RC may identify and establish voltage stability limits based on the voltage stability assessment results and will coordinate the voltage stability limits with the affected TOPs. Voltage stability limits may require development of new temporary flowgates.
   c. Voltage stability real-time and single-contingency limits will include a 5% MW margin.
   d. Voltage stability multiple-contingency limits will include a 2.5 % MW margin.
   e. A voltage stability limit more restrictive than an existing SOL will be identified as the revised SOL and communicated to affected entities prior to implementation in congestion management procedures.
   f. If system conditions in conjunction with real-time voltage stability assessments are determined to be stable, conditions within the 5% MW margin of the voltage stability limit than was previously defined, then the SPP RC may adjust the limit after coordinating an agreement with the affected TOPs.
   g. The RC will coordinate with the impacted TOPs to establish necessary mitigations and operating plans.