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Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is divided into six RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Region while associated Transmission Owners/Operators participate in another.

The Regional boundaries in this map are approximate. The highlighted area between SPP and SERC denotes overlap as some load-serving entities participate in one Region while associated transmission owners/operators (TOs/TOPs) participate in another.

<table>
<thead>
<tr>
<th>Code</th>
<th>Name</th>
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<tr>
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<td>Midwest Reliability Organization</td>
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<tr>
<td>NPCC</td>
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<td>RF</td>
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NERC | Dynamic Transfer Reference Document – Version 4 | 2019
Overview

Purpose
The purpose of this document is to provide guidance and encourage consistency in the industry on the responsibilities, requirements, and expectations placed upon parties involved in establishing a dynamic transfer. It is not within the scope of this reference document to require any organization to modify any existing dynamic transfers.

Terms

**Attaining Balancing Authority:** The Balancing Authority (BA) bringing generation or load into its effective control boundaries through dynamic transfer from the native BA

**Dynamic Transfer:** The provision of the real-time monitoring, telemetering, computer software, hardware, communications, engineering, energy accounting (including inadvertent interchange), and administration required to electronically move all or a portion of the real energy services associated with a generator or load out of one BA Area into another

**Dynamic Transfer Signal:** The electronic signal used to implement a pseudo-tie or dynamic schedule using either a metered value or a calculated value

**Dynamic Schedule or Dynamic Interchange Schedule:** A telemetered reading or value that is updated in real time and used as a schedule in the AGC/ACE (automatic generator control/area control error) equation and the integrated value of which is treated as a schedule for interchange accounting purposes

**Integration:** In the terms for dynamic schedule and pseudo-tie above means the value could be mathematically calculated or determined mechanically with a metering device and incorporated into the associated ACE calculations for the attaining and native BA

**Native BA:** The BA from which a portion of its physically interconnected generation and/or load is assigned from its effective control boundaries through dynamic transfer to the attaining BA

**Attaining Reliability Coordinator:** The Reliability Coordinator (RC) for the attaining BA

**Native RC:** The RC for the native BA

**Pseudo-Tie:** A time-varying energy transfer that is updated in real-time and included in the actual net interchange term (NIA) in the same manner as a tie line in the affected BA’s reporting ACE equation (or alternate control processes)
The key difference between pseudo-ties and dynamic schedules is often viewed only as a system control issue. Discussions are typically limited to how the transfer is implemented in each BA’s ACE equations and in the associated energy accounting process. Pseudo-ties are accounted for by all parties as actual interchange, and dynamic schedules are accounted for as scheduled interchange. However, there are other factors that must be considered when determining which type of dynamic transfer should be utilized for a given situation. The descriptions provided in this document are based on practical experience where dynamic transfers have been successfully implemented.

From a simple perspective, a dynamic schedule is a means of achieving a time-varying exchange of power where traditional block scheduling is not sufficient. Examples might be the partial or complete exchange of regulating obligations (see Appendix B: Supplemental Regulation Service as a Dynamic Schedule), the temporary provision of power under a reserve sharing agreement, or the exchange of power to serve a real-time demand signal.

Pseudo-ties are typically but not exclusively used to represent Interconnections between two BAs at a generation or load, similar to a physical tie line. These load/generators, however, are at locations where no other physical connection exists between the load/generation and the power system network of the responsible, attaining BA’s traditional control boundaries defined by its physical tie lines. In the instance of a pseudo-tie, the operational and procedural responsibility¹ for a source of load/generation is key and must be coordinated between all impacted BAs and RCs. In addition to system control responsibility that is traditionally considered, the responsibilities related to a pseudo-tie extend to such requirements as Disturbance Control Standard (DCS) recovery, load shedding, transmission and ancillary services, load forecasting, system operating limit/Interconnection reliability operating limit mitigation, etc. associated with the load/generation.

Although both pseudo-ties and dynamic schedules involve time-varying quantities, unlike for a pseudo-tie, a dynamic schedule may have no specific load/generation for which the attaining BA is operationally or procedurally responsible.

The choice of a pseudo-tie versus a dynamic schedule can be adapted to suit any implementation between the native and attaining BAs as long as both BAs agree which one is responsible for each of the obligations associated with the load/generation. For example, a pseudo-tie would typically be used to represent a generator owned by an attaining BA that is located within the physical tie line boundary of a native BA. However, a dynamic schedule implementation can be used in each BA’s ACE equation as long as responsibility for obligations, such as recovery during a DCS event, are clearly understood and accepted by both BAs.

¹ Procedural responsibility refers to which BA area’s, RC area’s and/or which ERO Region’s requirements will apply to the generator or load.
Chapter 1: Dynamic Transfer Implementation Considerations

There are numerous considerations that the attaining BA and the native BA must address during the design and implementation of a Dynamic Transfer. This chapter identifies areas that should be discussed and agreed upon during the development of a new Dynamic Transfer.

Dynamic transfers can be used for, but not limited to, the following scenarios:

- To transfer all, or a portion of, actual output of a specific generator(s) to another BA in real-time
- To enable resources in one BA to provide the real-time power requirements for a load physically located in another BA from resources in the native BA
- Enable generators, loads, or both in one BA to supply one or more interconnected operations services to generators and/or loads, or both, between the native and attaining in another BA
- To provide a mechanism for reserve sharing
- To provide supplemental regulation.

The particular dynamic transfer method to be utilized for a specific operating arrangement may be dependent on some or all of the following:

- The desired service(s) to be provided
- The capability to capture the dynamic transfer in system models
- Responsibility for forecasting load
- Responsibility for providing unit commitment and maintenance information
- Energy management system (EMS) capability

Each BA is obligated to fulfill its commitment to the Interconnection and not burden other BA(s). The use of a dynamic transfer does not in any way diminish this responsibility. The following list of obligations should be discussed and accounted for in the design and implementation of a dynamic transfer:

- Before implementing the dynamic transfer, all parties to the dynamic transfer must agree on all implementation details.
- Any errors resulting from an improperly implemented or operated dynamic transfer (including inadvertent interchange accumulations) must be resolved between the involved parties.
- Dynamic transfers must not include any control offsets that are not explicitly compliant with the requirements set forth in NERC Reliability Standards (e.g., unilateral inadvertent payback, Western Interconnection automatic time error control, etc.).
- Applicable tariff requirements of all involved or affected transmission providers and BA(s) must be met; this includes proper handling and accounting for energy losses.
- If the dynamic transfer includes a prearranged calculated assistance or distribution of responsibility between the native BA and the attaining BA for recovery from the loss of generation, then both BAs are responsible for ensuring that their respective DCS compliance requirements are met in accordance with NERC Standard BAL-002-3 — Disturbance Control Standard — Contingency Reserve for Recovery from a Balancing Contingency Event.

From a system modeling perspective, the assignment of load or generation into the control response of another BA
must be appropriately captured in the reliability analysis tools. It is the obligation of each BA involved in the dynamic transfer to ensure that the dynamic transfer of load or generation is coordinated with their TOP and RC so that the method of dynamic transfer can be considered in the system modeling of the generation or load affected and that the necessary data provision requirements are met. These provisions are listed as follows:

- To assure proper resource application, it is the responsibility of the attaining BA dynamically transferring load into its effective boundaries through pseudo-ties to ensure that load forecasts and subsequent BA reporting reflect the load incorporated within its BA boundaries. Conversely, when a dynamic schedule is used to serve load within another BA area, the BA where the load is electrically connected (native BA) must include that load in its BA load forecast and any subsequent reporting as needed.

- It is the responsibility of both the native BA/TOP/RC and attaining BA/TOP/RC to model any generation or load serving dynamic transfers in their respective power flow models, real-time assessments (RTAs) and modeled in the interchange distribution calculator (IDC) correctly. This modeling is required to ensure that affected BAs/TOPS/RCs study the generation or load regardless of the control boundary designations. This modeling also is necessary to ensure that each BA/TOP/RC can see the impact of the dynamic transfer on their systems.

- Dynamic transfers must not affect reliability adversely. If the reliability impact of a dynamic transfer that has been implemented as a pseudo-tie cannot be addressed adequately without modeling it in the IDC or other applicable RTA system models that use scheduled values, then the dynamic transfer must be performed via a dynamic schedule.

For both pseudo-ties and dynamic schedules, the BAs shall adjust their frequency bias setting to account for the frequency bias characteristics of the loads and/or resources being assigned between BA(s) in accordance with the NERC process as referenced in [Balancing Authority Area Footprint Change Tasks Reference Document](https://www.nerc.com/comm/OC/Operating%20Reliability%20Subcommittee%20ORS%202013/ORS_Presentations_Sep2018.pdf). There are occasions when changes are needed to bias settings outside of the normal schedule. Examples are footprint changes between BAs and major changes in load or generation or the formation of new BAs. In such cases the changing BAs should reference the [Balancing Authority Area Footprint Change Tasks Reference Document](https://www.nerc.com/comm/OC/Operating%20Reliability%20Subcommittee%20ORS%202013/ORS_Presentations_Sep2018.pdf) and work with their Regions and NERC to confirm appropriate changes to bias settings, FRO, CPS limits and Inadvertent Interchange balances.

The native, attaining, and intermediate BAs must carefully coordinate many aspects related to dynamic transfers. Failure to do so may result in the creation of reliability problems for the Interconnection, may create after-the-fact energy accounting and billing problems, and may cause violations of industry standards. Below is a list of conditions that the participating BAs should ensure have been addressed prior to implementing a new dynamic transfer:

- Control offsets are compliant with applicable industry standards
- Tariff requirements are met
- DCS reporting requirements have been addressed
- Transmission service has been addressed
- Need for inclusion in reliability tools has been addressed
- Transferred loads and/or generation are accounted for in energy dispatch
- Transferred loads and/or generation are still included in relevant RTA tools
- Frequency bias impacts have been addressed
- Contingency plans for loss of dynamic transfer signal and telecommunications have been addressed
• Contingency plans for transmission constraints that prohibit the dynamic transfer
• Industry compliance issues such as NERC and NAESB have been addressed
• Energy accounting practices are consistent, including losses
• The ancillary service provision has been addressed
• Impact on reserve requirements have been addressed
• Impact on under-frequency load shedding relays have been addressed
• Dynamic Transfers must be included in congestion management
• Primary and secondary telemetry methods for required data have been addressed
• Ramp rates limitations have been addressed

Table 1 describes and outlines the obligations associated with the typical historical application of pseudo-ties and dynamic schedules related to many of the topics addressed above. In practical application, however, both the native and attaining BAs can agree to exchange the obligations from that shown in the Table 1. Additional coordination obligations with respect to pseudo ties and RC are listed in Chapter 53 Pseudo-Tie Implementation and Coordination.

<table>
<thead>
<tr>
<th>BA’s Obligation/modeling</th>
<th>Pseudo-tie</th>
<th>Dynamic schedule</th>
</tr>
</thead>
<tbody>
<tr>
<td>Generation planning and reporting and outage coordination</td>
<td>Attaining BA</td>
<td>Typically, native BA but may be reassigned (wholly or a portion) to the attaining BA</td>
</tr>
<tr>
<td>CPS and DCS recovery/reporting and RMS</td>
<td>Attaining BA</td>
<td>Attaining and/or native BA (depending on agreements)</td>
</tr>
<tr>
<td>Operational responsibility</td>
<td>Attaining BA</td>
<td>Native BA</td>
</tr>
<tr>
<td>BA services</td>
<td>Attaining BA</td>
<td>Native BA</td>
</tr>
</tbody>
</table>

Table 1: Assignment of BA Obligations

<table>
<thead>
<tr>
<th>BA’s Obligation/modeling</th>
<th>Pseudo-tie</th>
<th>Dynamic schedule</th>
</tr>
</thead>
<tbody>
<tr>
<td>FERC Open Access</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Transmission Tariff (OATT) Schedules 3–6 and other ancillary services as required</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ancillary services associated with transmission FERC OATT Schedules 1–2 and other ancillary services as required</td>
<td>Attaining/native BA (as agreed)</td>
<td>Attaining/Native BA (as agreed)</td>
</tr>
<tr>
<td>ACE frequency bias calc/setting</td>
<td>The native and attaining BA(s) shall adjust their frequency bias setting to account for the frequency bias characteristics of the loads and/or resources being assigned between BA(s) by the pseudo-tie</td>
<td>The attaining BA should include the load from its dynamic schedule as a part of its forecast load to set frequency bias requirement. The native BA should change its load used to set frequency bias setting by the same amount in the opposite direction.</td>
</tr>
<tr>
<td>Load forecasting and reporting</td>
<td>Attaining BA</td>
<td>Native BA</td>
</tr>
</tbody>
</table>
## Chapter 1: Dynamic Transfer Implementation Considerations

<table>
<thead>
<tr>
<th>Manual load shedding during an Energy Emergency Alert</th>
<th>Attaining BA</th>
<th>Native BA</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coordination with RC for inclusion in congestion Management</td>
<td>Attaining BA if within one RC</td>
<td>Native BA if within one RC</td>
</tr>
<tr>
<td></td>
<td>Both attaining and native BA if spanning multiple RC’s</td>
<td>Both attaining and native BA if spanning multiple RC’s</td>
</tr>
</tbody>
</table>

**Note:** This table contains the typical BA obligations that have been utilized throughout the industry for pseudo- ties and Dynamic Schedules. However, for any specific dynamic transfer implementation, both the native and attaining BAs can agree to exchange the obligations from that shown in the table.
Chapter 2: Dynamic Schedule Implementation and Coordination

A dynamic schedule is implemented as an interchange transaction that is modified in real-time to transfer time-varying amounts of power between BAs. A dynamic schedule typically does not change a BA’s or RC’s operational responsibility (i.e., the native BA/RC continues to exercise operational control over and provides basic BA/RC services to the dynamically scheduled resources).

Dynamic schedules are to be accounted for as interchange schedules by the source, sink, and contract intermediary BA(s) both in their respective ACE equations and throughout all of their energy accounting processes. Requirements to incorporate a dynamic schedule into the contract intermediary BA’s ACE are subject to regional procedures.

All dynamic schedules used for supplemental regulation or to assign the control of generation, loads, or resources from one BA to another must meet the following requirements:

- **Telemetry**: Appropriate telemetry must be in place and incorporated by all affected BA(s) in accordance with all NERC Reliability Standards, especially the Disturbance Control Performance standard.

- **Transmission Service**: Prior to implementation of the dynamic schedule of load or generation, all applicable NERC interchange Reliability Standards need to be met, including ancillary services and provision of losses.

  If transmission service between the source and sink BA(s) is curtailed then the allowable range of the magnitude of the schedules between them, including dynamic schedules, may have to be curtailed accordingly. All BAs involved in a dynamic schedule curtailment must also adjust the dynamic schedule signal input to their respective ACE equations to a common value. The value used must be equal to or less than the curtailed dynamic schedule tag. Since dynamic schedule tags are generally not used as dynamic transfer signals for ACE, this adjustment may require manual entry or other revision to a telemetered or calculated value used by the ACE.

- **System Modeling**: When a dynamic schedule is used to serve load within another BA area, the BA where the load is electrically connected (native BA) must include this load in its BA load forecast for both energy dispatch and RTA and any subsequent reporting as needed. This is necessary because the system models must adequately capture the projected demand on the system (load forecast) and the projected supply (provided by the electronic tagging system).

- **Dynamic Schedule Coordination and Scheduling**: The implementation of a dynamic schedule must be through the use of an interchange transaction between BA(s). As such, all dynamic schedules shall be implemented in accordance with NERC interchange reliability standards. All dynamic schedule impacts are reflected in market flow calculations for entities that report market flows unless that entity has requested an exemption and that exemption has been requested and approved as specified in Appendix D - NERC ORS Dynamic Tag Exclusion Process.

  Energy exchanged between the source, sink, and intermediary BA(s) as a dynamic schedule is the metered or calculated (obtained by the integration of the dynamic schedule signal) energy for the loads and/or resources. Agreements must be in place with the applicable transmission providers to address the physical or financial provision of transmission losses.

  The native BA must ensure that agreements are in place that define the responsibility for providing applicable ancillary/interconnected operations services.

  If the power flows associated with the dynamic schedule are expected to be bi-directional, two separate dynamic schedules are required (each schedule to be implemented as unidirectional following the “gen-to-load” direction convention). This expectation is a result of the fact that transmission service would be
required for the dynamic schedules and most often import and export transmission services are provided as separate reservations.

- **Contingency Response:** Before implementation of the dynamic schedule, the involved BAs shall agree on a plan. The plan should ensure that the following occur:

  - To operate during a loss of the dynamic schedule telemetry signal such that all involved BAs are using the same value (including periods of time when the interconnection between them is unavailable). The BA(s) may agree to hold the last known good value, use an average load profile value, or have one party provide the other with a manual override value at some acceptable frequency of update.

  - To serve the load during system conditions which prevent delivery of the dynamic schedule from the generation to the load.

  - To redispatch the generation that had served the dynamically scheduled load prior to the system conditions which prevent delivery from the generation to the load.

- **Compliance with NERC Reliability Standards**

  The implementation of a dynamic schedule may confer upon the attaining BA additional responsibilities for compliance with NERC Reliability Standards for the load or generation that has been transferred.
Chapter 3: Pseudo-Tie Implementation and Coordination

Pseudo-ties are often employed to assign generators, loads, or both from the BA to which they are physically connected to a BA that has effective operational control. Thus, pseudo-ties often provide for a change of BA operational responsibility from the native to the attaining BA and make the attaining BA provider of BA services at the same time. In practice, pseudo-ties may be implemented based upon metered or calculated values. All BAs involved account for power exchange and associated transmission losses as actual interchange between the BAs in their ACE equations and throughout all of their energy accounting processes.

All pseudo-ties used to assign generation, loads, or resources from the native BA to the attaining BA must meet the following requirements:

- **Telemetry**: Prior to implementation of the pseudo-tie transfer of load or generation, all applicable NERC Reliability Standards need to be met, including:
  - common metering points
  - adequate communications infrastructure

  The requirement for common metering points and adequate communications infrastructure does not imply specific ownership of telemetry devices.

- **Transmission Service**: Prior to implementation of the pseudo-tie transfer of load or generation, each involved BA shall ensure that the dynamic transfer is implemented such that the tariff requirements of the applicable transmission provider(s), including applicable ancillary services and provision of losses, are met.

  If transmission service between the native and attaining BA(s) is curtailed, then the allowable range of the magnitude of the pseudo-ties between them must be limited accordingly to these constraints.

  Agreements must be in place with the applicable transmission providers to address the physical and/or financial provision of transmission losses.

- **System Modeling**: The attaining BA dynamically transferring load into its effective boundaries through a pseudo-tie shall ensure that load forecasts used for energy dispatch and subsequent BA reporting reflect the load incorporated within its BA boundaries. The native BA would continue to consider this load in load forecasts used for its RTA.

  If the reliability impact of the pseudo-tie cannot be accurately captured in the IDC and/or any other RTA system models of the reliability entities impacted by the dynamic transfer, then the dynamic transfer must be implemented as a dynamic schedule.

- **Pseudo-Tie Coordination and Scheduling**: Subsequent to moving load or resources into an attaining BA through pseudo-tie transfers, all interchange transactions or other energy transfers to the loads or from the resources must be coordinated among the attaining intermediary and native BAs in accordance with the NERC Reliability Standards.

  - The attaining BA assumes responsibility for BA services required by the assigned loads and/or resources. The attaining BA assumes all regulation, contingency reserves, and other BA responsibilities for the loads and/or resources in question.

  - Energy exchanged between the native and attaining BA(s) by the pseudo-tie method is accounted for by the associated revenue meter reading (if such meter exists at the dynamically assigned resource or load) or energy calculated by integrating the associated telemetered real-time signal.
• Contingency Response: Before implementation of the pseudo-tie transfer, the involved BAs shall agree on a plan:
  
  ▪ **The BA will** operate during a loss of the pseudo-tie transfer telemetry signal such that all involved BAs are using the same value, including periods of time when the interconnection between them is unavailable. The BA(s) may agree to hold the last known good value, use an average load profile value, or have one party provide the other with a manual override value at some acceptable frequency of update.
  
  ▪ **The BA will** serve the load during system conditions that prevent delivery of the pseudo-tie transfer from the generation to the load.
  
  ▪ **The BA will** redispach the generation that had served the pseudo-tie transfer load prior to the system conditions which prevent delivery from the generation to the load.

• Compliance with NERC Operating Standards: The implementation of a pseudo-tie transfers may confer upon the attaining BA additional responsibilities for compliance with NERC Reliability Standards for the load or generation that has been transferred.

In addition to the BA to BA coordination requirements listed above, the following items must also be addressed to ensure proper coordination between all impacted BAs and RCs:

• **BA and RC interaction during approval process:** Attaining, Intermediate, and native BAs and attaining and native RCs should be part of the approval process for implementing pseudo-Tie(s). Attaining BA is defined as a BA that brings generation or load into its effective control boundaries through a Dynamic Transfer from the native BA. Native BA is defined as BA from which a portion of its physically interconnected generation and/or load is transferred from its effective control boundaries to the attaining BA through a dynamic transfer.

• **Requirements to submit outages for pseudo-tied equipment as well as other RC responsibilities (i.e. next day studies, etc.)** will be coordinated between the attaining and native RCs.

  RC responsibilities for the pseudo-tie(s) shall be agreed upon between involved parties at time of registration of the arrangement. Unit commitment/dispatch plan information for up to seven days out should be made available to the native RC and interconnected TOP upon request.

  Transmission service that uses pseudo-tie(s) should be accurately reflected in the available flowgate capability or available transfer capability calculations.

  Prior to the implementation of new pseudo-tie(s) or changes to existing pseudo-tie(s), both the attaining and native RCs should have a mutual understanding how operational issues related to the pseudo-tie(s) will be administered. These discussions should include designation of each RC responsibilities for the pseudo-tied facility and how reliability-related changes to the pseudo-tied transaction will be implemented.

• **Firm transmission should be used for the entire path for the Eastern Interconnection:** For proper allocation of network and native load based on current generation-to-load calculation in the IDC, a pseudo-tie must use firm transmission service. Transmission service should be studied with the points of receipt and points of delivery reflecting the specific location of generator or load being pseudo-tied. If a transmission service provider offers conditional firm transmission service based on their tariff, the service must be coordinated with their native RC to ensure the accuracy of their congestion management.
If firm transmission service is not used for all portion of the path between the native and attaining BAs, the attaining BA must set the pseudo tied generator’s priority to non-firm to be consistent with the PFV requirements set forth by NAESB.

- **Native RC should have authority to direct the generator/load, in order to address local area issues:**
  The native RC/TOP should coordinate with the attaining BA/RC of a pseudo-tied generator to dispatch the pseudo-tied generator to a level that is deemed reliable to manage congestion in a local area issue. The native RC/TOP may need to request commitment modifications to manage congestion in a local area.

  The native RC and/or TOP should retain the right to issue operating instructions to the pseudo-tied unit to modify unit output if needed to resolve a local transmission reliability issue. If there are conflicts in operating instructions between the native RC/TOP and the attaining RC/TOP of a pseudo-tied generator, the native RC/TOP and attaining RC/TOP shall work to resolve the conflict with the native RC/TOP having priority authorization to resolve the reliability issue.

- **The market entity must be able to accurately calculate market flow impacts from the source:**
  The market entity, including an external resource/load or collection thereof, should only implement a pseudo-tie if the market entity’s real-time network model is expanded to at least the location of the source/sink of the pseudo-tie and its surrounding buses. This is to ensure that the market entity reports market flow that is reflective of the system conditions throughout the path of the transfer inclusive of external areas on that path and is able to achieve any relief obligation that may be assigned as result of this arrangement. If relief obligation is not met through an accepted congestion management (market flow reallocation or transmission loading relief), manual RC actions may apply.

- **The attaining entity must ensure sufficient detail in the IDC model to calculate generation-to-load impacts from the source:**
  An entity whose pseudo-tie is not being tagged, including an external resource/load or collection thereof, must ensure there is sufficient detail in the IDC model to calculate the generation-to-load impacts that are reflective of the system conditions throughout the path of the transfer. The RC should ensure any relief obligation that may be assigned as result of this arrangement are realistic. If relief obligation is not met through TLR, a manual RC intervention may apply.

- **Notification to the industry stakeholders:**
  A notification of future requests for pseudo-tie(s) should be made to the NERC Operating Reliability Subcommittee (ORS) by the attaining RC. The attaining RC will confirm how these guidelines will be met before implementation of the pseudo-tie(s). To make this process manageable, only pseudo-tie notifications where the resource capacity exceeds 20 MW at a single bus, or where the amount of peak load exceeds 50 MW at a single bus, will need to be made to the NERC ORS. The attaining RC only notifies the NERC ORS of such pseudo-tie changes to improve situational awareness, and the NERC ORS will not be providing approval or denial of such changes.

  Sufficient notice of a pseudo-tie addition needs to be given to affected BAs, TOPS, and RCs to allow changes to be made to their EMS and accounting systems when a pseudo-tie is added or removed. This work can take several months to complete.

- **Pseudo-Tie removal**
  There are no similar requirements to notify NERC ORS under this guideline when a pseudo-tie is removed that results in returning the resource/load back to its native BA/RC.

  Sufficient notice of a pseudo-tie removal needs to be given to affected BAs, TOPS, and RCs to allow changes to be made to their EMS and accounting systems when a pseudo-tie is added or removed. This work can take several months to complete.
Appendix A: ACE Equation Implications of Dynamic Transfers

A Balancing Authority’s internal obligations, along with the small additional “bias” obligation to maintain frequency, is represented via a real-time value called area control error (ACE), estimated in MW. Dynamic Transfers have an impact on the calculation of ACE and should be included into the respective ACE calculations as part of implementation. This appendix provides the base ACE equation along with examples of how to adjust the base a BA’s ACE equation to support the implementation of dynamic transfers.

\[
ACE = ([\text{net actual interchange}] - [\text{net schedule interchange}]) - 10B (F_a - F_s) - IME + IATEC
\]

\[
ACE^2 = ([\text{NIA}] - [\text{NIS}]) - 10B (F_a - F_s) - IME + IATEC
\]

\(^2\) IATEC is specifically used in the Western Interconnection

Commented [AC52]: This equations without context are not ideal. A sentence or two introducing each would be helpful

Commented [ORA53RS2]: Added a few introductory sentences.

Commented [ORA54]: NERC to address spacing issues
where:

**Net Actual Interchange (\(NIA\))**

Affected by pseudo-ties/AGC interchanges

\[ NIA = (\text{SUM of Tie Lines}) + (\text{SUM of pseudo-ties}) \]

\[ NIA = (NI_a) + (NI\text{APTGE} - NI\text{APTGI} - NI\text{APTLLE} + NI\text{APTLI} + NI\text{ARSE} - NI\text{ARSI}) \]

where:

- \(NI_a\) = Net sum of tie line flows
- \(NI\text{APTGE}\) = sum of AGC pseudo-tie interchange generation external to the attaining BA.
- \(NI\text{APTGI}\) = sum of AGC pseudo-tie interchange generation internal to the BA (native BA).
- \(NI\text{APTLLE}\) = sum of AGC pseudo-tie interchange load external to the BA (attaining BA).
- \(NI\text{APTLI}\) = sum of AGC pseudo-tie interchange load internal to the BA (native BA).
- \(NI\text{ARSE}\) = supplemental regulation service external to the BA (BA purchasing supplemental regulation service) via pseudo-tie. See Appendix C.
- \(NI\text{ARSI}\) = Supplemental regulation service internal to the BA (BA selling supplemental regulation service) via pseudo-tie. See Appendix C.

and where values for all generation and load terms are assumed to be positive quantities.
Appendix A: ACE Equation Implications of Dynamic Transfers

**Net Scheduled Interchange (NIS)**
Affected by dynamic schedules and supplemental regulation services.

\[
NIS = (\text{SUM of non-dynamically scheduled transactions}) + (\text{SUM of Dynamic Schedules}) = (NIs) + (-NISDSGE + NISDSGI + NISDSLE - NISDSLI - NISRSE + NISRSI)
\]

where:
- \(NIs\) = Net sum of non-dynamically scheduled transactions,
- \(NISDSGE\) = Sum of dynamically scheduled generation external to the attaining BA,
- \(NISDSGI\) = Sum of dynamically scheduled generation internal to the native BA,
- \(NISDSLE\) = Sum of dynamically scheduled load external to the attaining BA,
- \(NISDSLI\) = Sum of dynamically scheduled load internal to the native BA,
- \(NISRSE\) = Supplemental regulation service external to the BA (BA purchasing the supplemental regulation service). See Appendix B.
- \(NISRSI\) = Supplemental regulation service internal to the BA (BA selling the supplemental regulation service). See Appendix B.

Terms Unaffected by Dynamic Transfers

- \(B\) = BA frequency bias
- \(F_A\) = actual frequency
- \(F_S\) = scheduled frequency
- \(I_{ME}\) = meter error correction
- \(I_{ATEC}\) = automatic time error correction (If implemented within Interconnection)

\[
ACE = \left(\left\{\left(\left[NIs - \left(NISDSGE - NISDSGI - NISDSLE + NISDSLI + NISRSE - NISRSI\right)\right] - (NIs) + (-NISDSGE + NISDSGI + NISDSLE - NISDSLI - NISRSE + NISRSI)\right)\right\} - 108(F_A - F_S) - I_{ME} + I_{ATEC}\right)
\]
The following tables depict the specific ACE equation components that should be included by each BA if implementing dynamic transfers.

**Application of Pseudo-ties in ACE by BA(s)**
Application of pseudo tie between adjacent BA(s) (BA\textsubscript{A} and BA\textsubscript{B} are adjacent)

<table>
<thead>
<tr>
<th>Pseudo-Tie Transfer</th>
<th>Path</th>
<th>BA\textsubscript{A} ACE Inclusions</th>
<th>BA\textsubscript{B} ACE Inclusions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Generator from BA\textsubscript{A} to BA\textsubscript{B}</td>
<td>BA\textsubscript{A} -&gt; BA\textsubscript{B}</td>
<td>NI\textsubscript{APTGI}</td>
<td>NI\textsubscript{APTGE}</td>
</tr>
<tr>
<td>Load from BA\textsubscript{A} to BA\textsubscript{B}</td>
<td>BA\textsubscript{A} -&gt; BA\textsubscript{B}</td>
<td>NI\textsubscript{APTLI}</td>
<td>NI\textsubscript{APTEL}</td>
</tr>
</tbody>
</table>

Application of pseudo-tie between two BA(s) including an intermediate BA (BA\textsubscript{A} and BA\textsubscript{B} are non-adjacent and flow traverses BA\textsubscript{E})

<table>
<thead>
<tr>
<th>Pseudo-Tie Transfer</th>
<th>Path</th>
<th>BA\textsubscript{A} ACE Inclusions</th>
<th>BA\textsubscript{E} ACE Inclusions</th>
<th>BA\textsubscript{B} ACE Inclusions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Generator from BA\textsubscript{A} to BA\textsubscript{E}</td>
<td>BA\textsubscript{A} -&gt; BA\textsubscript{E} -&gt; BA\textsubscript{B}</td>
<td>NI\textsubscript{APTGI}</td>
<td>NI\textsubscript{APTGI}</td>
<td>NI\textsubscript{APTGE}</td>
</tr>
<tr>
<td>Load from BA\textsubscript{A} to BA\textsubscript{E}</td>
<td>BA\textsubscript{A} -&gt; BA\textsubscript{E} -&gt; BA\textsubscript{B}</td>
<td>NI\textsubscript{APTLI}</td>
<td>NI\textsubscript{APTEL}</td>
<td>NI\textsubscript{APTEL}</td>
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</tbody>
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**Application of Dynamic Schedules in ACE by BA(s)**
Application of dynamic schedules between adjacent BA(s)

<table>
<thead>
<tr>
<th>Dynamic Schedule Transfer</th>
<th>Path</th>
<th>BA\textsubscript{A} ACE Inclusions</th>
<th>BA\textsubscript{B} ACE Inclusions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Generator from BA\textsubscript{A} to BA\textsubscript{B}</td>
<td>BA\textsubscript{A} -&gt; BA\textsubscript{B}</td>
<td>NI\textsubscript{DSGI}</td>
<td>NI\textsubscript{DSGI}</td>
</tr>
<tr>
<td>Load from BA\textsubscript{A} to BA\textsubscript{B}</td>
<td>BA\textsubscript{A} -&gt; BA\textsubscript{B}</td>
<td>NI\textsubscript{DSLI}</td>
<td>NI\textsubscript{DSLE}</td>
</tr>
</tbody>
</table>

Application of dynamic schedules between two BA(s), including an intermediate BA (BA\textsubscript{A} and BA\textsubscript{B} are non-adjacent and flow traverses BA\textsubscript{E})

<table>
<thead>
<tr>
<th>Dynamic Schedule Transfer</th>
<th>Path</th>
<th>BA\textsubscript{A} ACE Inclusions</th>
<th>BA\textsubscript{B} ACE Inclusions</th>
<th>BA\textsubscript{E} ACE Inclusions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Generator from BA\textsubscript{A} to BA\textsubscript{E}</td>
<td>BA\textsubscript{A} -&gt; BA\textsubscript{E} -&gt; BA\textsubscript{B}</td>
<td>NI\textsubscript{DSGI}</td>
<td>NI\textsubscript{DSGI}</td>
<td>NI\textsubscript{DSGI}</td>
</tr>
<tr>
<td>Load from BA\textsubscript{A} to BA\textsubscript{E}</td>
<td>BA\textsubscript{A} -&gt; BA\textsubscript{E} -&gt; BA\textsubscript{B}</td>
<td>NI\textsubscript{DSLI}</td>
<td>NI\textsubscript{DSLE}</td>
<td>NI\textsubscript{DSLE}</td>
</tr>
</tbody>
</table>
### Numeric Examples

Assume: Net sum of tie flows = 0, 
Net sum of non-dynamically scheduled transactions = 0, 
\(F_A = F_A\), 
and \(I_{ME} = 0\)

In these examples, BAA will become the attaining BA for load Y and generator Z. Similarly, BAB East will become the attaining BA for load X and generator W.

#### Using Dynamic Schedules

ADD TABLE REFERENCE to obtain the correct net scheduled interchange terms for the dynamic schedules, the ACE equation for BAA becomes the following:

\[
ACE_{BA_A} = NIA - NIS = NIA - (NIs - NISDSGE(Z) + NISDSGI(W) + NISDSLE(Y) - NISDSLI(X))
\]

Substituting the values in the example as positive quantities, the equation becomes:

\[
ACE_{BA_A} = 0 - (0 - 200 + 100 + 75 - 50) = 75
\]

#### Using Pseudo-Ties

ADD TABLE REFERENCE to obtain the correct net actual interchange terms for the pseudo-ties, the ACE equation becomes the following:

\[
ACE_{BA_A} = NIA - NIS = (NIA + NIAPTGI(Z) - NIAPTGE(W) - NIAPTGI(Y) + NIAPTGE(X)) - NIS
\]

Substituting the values in the example as positive quantities, the equation becomes:

\[
ACE_{BA_A} = (0 + 200 - 100 - 75 + 50) - 0 = 75
\]
Using both Dynamic Schedules and Pseudo-ties

Assume that the generation will be modeled as dynamic schedules and the loads as pseudo-ties. INSERT TABLE REFERENCES to obtain the correct net scheduled interchange and net actual interchange terms for the dynamic transfers, the ACE equation for BA West becomes as follows:

\[
\text{ACE BA}_A = \text{NIA}_A - \text{NI}_A = (\text{NIA}_A - \text{NIA}_\text{APFLEX}) - (\text{NI}_A - \text{NI}_\text{LOAD})(X) + \text{NI}_\text{LOAD}(Y))
\]

\[
= (\text{NIA}_A - \text{Load Y} + \text{Load X}) - (\text{NI}_A - \text{Gen Z} + \text{Gen W})
\]

Substituting the values in the example as positive quantities, the equation becomes:

\[
\text{ACE BA}_A = (0 - 75 + 50) - (0 - 200 + 100)
\]

\[
= (0 - 25) - (0 - 100)
\]

\[
= -25 + 100 = 75
\]

**Note:** In all cases, the ACE value is the same regardless of the dynamic transfer method(s) used.
Appendix B: Supplemental Regulation Service as a Dynamic Schedule

Supplemental regulation service is when one BA provides part of the regulation requirements of another BA. The BA(s) implement a dynamic schedule that incorporates the calculated portion of the ACE signal that has been agreed upon between them. This is accomplished by adding another component to the scheduled interchange ACE equation for both BA(s). Care should be taken to maintain the proper sign convention to ensure proper control with the BA purchasing regulation service subtracting the supplemental regulation service from the scheduling component of their ACE while the BA providing the service adds it to the scheduling component of their ACE.

If the supplemental regulation service includes a calculated assistance between the native BA and the attaining BA for recovery from the loss of generation, then both BA(s) are responsible for assuring that DCS compliance reporting requirements are met in accordance with NERC Standard BAL-002-3 — Disturbance Control Standard — Contingency Reserve for Recovery from Balancing Contingency Event.

The ACE equation modifications required for supplemental regulation service are as follows:

**ACE Equation Modifications**

Typically:

\[ \text{ACE} = (\text{NIA} - \text{NIS}) - 10B (\text{FA} - \text{FS}) - \text{IME} \]

where:

- \( \text{NIA} \) = net actual interchange
- \( \text{NIS} \) = net scheduled interchange
- \( B \) = BA frequency bias
- \( \text{FA} \) = actual frequency
- \( \text{FS} \) = scheduled frequency
- \( \text{IME} \) = meter error correction

For a DYNAMIC SCHEDULE the \( \text{NIA} \) remains unchanged, but to implement supplemental regulation service, the \( \text{NIS} \) term becomes as follows:

\[ \text{NIS} = \text{NIs} - \text{NISDSGE} + \text{NISDSGI} + \text{NISDGLE} - \text{NISDSLI} - \text{NISRSE} + \text{NISRSI} \]

where:

- \( \text{NIs} \) = Net sum of non-dynamically scheduled transactions
- \( \text{NISDSGE} \) = sum of dynamically scheduled generation external to the BA (attaining BA)
- \( \text{NISDSGI} \) = sum of dynamically scheduled generation internal to the BA (native BA)
- \( \text{NISDGLE} \) = sum of dynamically scheduled load external to the BA (attaining BA)
- \( \text{NISDSLI} \) = sum of dynamically scheduled load internal to the BA (native BA)
- \( \text{NISRSE} \) = Supplemental regulation service external to the BA (BA purchasing the supplemental regulation service)
- \( \text{NISRSI} \) = Supplemental regulation service internal to the BA (BA selling the supplemental regulation Service)

and where supplemental regulation service for an overgeneration condition is assumed to be negative and for under generation it is positive to achieve the desired effect via \( \text{NIs} \) on ACE as described in the *NAESB WEQ Area Control Error (ACE) Equation Special Cases Standards - WEQBPS – 003-000*.
Supplemental Regulation as Dynamic Schedule - Numeric Example

In this example, BAA is purchasing 15 Mw of supplemental regulation. Similarly, BAB is selling 15 Mw of supplemental regulation.

Using the correct net scheduled interchange terms for supplemental regulation as a dynamic schedule, the ACE equation for BAA becomes as follows:

\[ \text{ACE BAA} = \text{NIA} - \text{NIS} \]
\[ = \text{NIA} - (\text{NIs} - \text{NISDSGE} + \text{NISDSGI} + \text{NISDGLE} - \text{NISDSLI} - \text{NISRSE} + \text{NISRSI}) \]

simplifying for applicable terms for this example yields,
\[ = \text{NIA} - (\text{NIs} - \text{NISRSE}) \]

Since purchaser BAA is in an under-generating condition in this example, the supplemental regulation term is positive and substitution in the equation becomes:

\[ \text{ACE BAA} = 0 - (20 - 15) \]
\[ = 0 - (5) = -5 \]

Similarly, the ACE equation for BA East becomes:

\[ \text{ACE BAB} = \text{NIA} - \text{NIS} \]
\[ = \text{NIA} - (\text{NIs} - \text{NISDSGE} + \text{NISDSGI} + \text{NISDGLE} - \text{NISDSLI} - \text{NISRSE} + \text{NISRSI}) \]

simplifying for applicable terms for this example yields,
\[ = \text{NIA} - (\text{NIs} + \text{NISRSI}) \]
Again, since purchaser BAₜ is in an under generating condition in this example, the supplemental regulation term is positive and substitution in the equation becomes as follows:

\[
\text{ACE BAₜ} = 0 - (-20 + 15) \\
= 0 - (-5) = 5
\]
Appendix C: Supplemental Regulation Service as a Pseudo-Tie

Supplemental regulation service is when one BA provides all or part of the regulation requirements of another BA. The BA(s) implement a pseudo-tie that incorporates the calculated portion of the ACE signal that has been agreed upon between them. This is accomplished by adding another component to the actual interchange component of the ACE equation for both BA(s). Care should be taken to maintain the proper sign convention to ensure proper control.

If the supplemental regulation service includes a calculated assistance between the native BA and the attaining BA for recovery from the loss of generation, then both BA(s) are responsible for assuring that DCS compliance reporting requirements are met in accordance with NERC Standard BAL-002-3 — Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event.

The ACE equation modifications required for supplemental regulation service are as follows:

ACE Equation Modifications

Typically:

\[ \text{ACE} = (N_{IA} - N_{IS}) - 10B (F_{A} - F_{S}) - I_{ME} \]

where:

- \( N_{IA} \) = net actual interchange
- \( N_{IS} \) = net scheduled interchange
- \( B \) = BA frequency bias
- \( F_{A} \) = actual frequency
- \( F_{S} \) = scheduled frequency
- \( I_{ME} \) = meter error correction

For a pseudo-tie with supplemental regulation, the \( N_{IS} \) remains unchanged, but the \( N_{IA} \) term becomes as follows:

\[ N_{IA} = N_{Ia} + (N_{IAPTGE} - N_{IAPTGI} - N_{IAPTLE} + N_{IAPTLI} + N_{ISRE} - N_{ISRI}) \]

where:

- \( N_{Ia} \) = Net sum of tie line flows
- \( N_{IAPTGE} \) = sum of AGC interchange generation external to the attaining BA.
- \( N_{IAPTGI} \) = sum of AGC interchange generation internal to the BA (native BA).
- \( N_{IAPTLE} \) = sum of AGC interchange load external to the BA (attaining BA).
- \( N_{IAPTLI} \) = sum of AGC interchange load internal to the BA (native BA).
- \( N_{ISRE} \) = supplemental regulation service external to the BA (BA purchasing the supplemental regulation service) via pseudo-tie.
- \( N_{ISRI} \) = supplemental regulation service internal to the BA (BA selling the supplemental regulation service) via pseudo-tie.

As with dynamic schedules for both the purchasing and selling BAs, supplemental service being provided to alleviate overgeneration has a negative sign while supplemental service being provided to alleviate under generation has a positive sign.
Supplemental Regulation as Pseudo-Tie - Numeric Example

Assume: Net sum of tie flows = 0,
Net sum of non-dynamically scheduled transactions = 20 Mw from BAA-West to BAA-East,
F_A = F_A,
and IME = 0

In this example, BAA will become the BA purchasing 15 Mw of supplemental regulation. Similarly, BAs will become
the BA selling 15 Mw of supplemental regulation.

Using the correct net actual interchange terms for supplemental regulation as a pseudo-tie, the ACE equation for
BAA becomes as follows:

\[ ACE_{BAA} = NIA - NIS \]

\[ = (NIa + NIAPTGE - NIAPTGI - NIAPTLE + NARSE - NARSI) - NIS \]

simplifying for applicable terms for this example yields,

\[ = (NIa + NARSE) - NIS \]

Since purchaser BAA is in an under-generating condition in this example, the supplemental regulation term
is positive and substitution in the equation becomes as follows:

\[ ACE_{BAA} = (0 + 15) - 20 \]

\[ = 15 - 20 = -5 \]

Similarly, the ACE equation for BAA-East becomes:

as follows: \[ ACE_{BAA} = NIa - NIS \]

\[ = (NIa + NIAPTGE - NIAPTGI - NIAPTLE + NARSE - NARSI) - NIS \]

simplifying for applicable terms for this example yields,

\[ = (NIa - NARSI) - NIS \]
Again, since purchaser BA is in an under generating condition in this example, the supplemental regulation term is positive and substitution in the equation becomes as follows:

\[ \text{ACE BA} = (0 - 15) - (-20) \]
\[ = -15 + 20 = 5 \]
Appendix D: Dynamic Tag Exclusion Process

Introduction
Over the years, numerous requests were made to the Interchange Distribution Calculator Working Group (IDCWG) and the ORS in order to accommodate special arrangements for different BAs to support congestion management actions that need to be reflected in the IDC, such as the exclusion of tags with a specific source and sink combination due to the MW impact being included in different curtailable products. These requests have been, up to this point, handled on a case-by-case basis as there is not a consistent process or set of guidelines to ensure such arrangements are implemented with no degradation to reliability or change in equity status for the products.

The ORS created a Task Force to work with the IDCWG to develop a process for the exclusion of tags.

Applicability
This process is applicable to RCs and BAs that manage dynamic tag(s).

Dynamic Tag Exclusion Management

Approval process
The NERC ORS is not tasked or qualified to approve equity-related issues. The ORS is tasked with ensuring reliability is maintained. Therefore, prior to requesting NERC ORS approval to allow the IDC to ignore a Dynamic Schedule tag, the requesting entity is expected to coordinate with NAESB BPS and/or applicable congestion management oversight policy committees to ensure no equity concerns exist. In addition, the requesting entity must also have approval from the IDCWG to ensure no technical concerns exist. Then the entity may request approval from the ORS.

Requirements for incorporating Dynamic Schedules into Market Flow
If the tagged dynamic schedule MW are converted to market flow and ignored by the IDC, the market flow MW representing the converted tag shall have a priority that is no higher than it would have been if the tag was not ignored.

For nonmarket entities, an otherwise tagged MW shall preserve the priority of the transaction if converted to a product not requiring a tag (gen-to-load).

Entity with Flowgate(s) impacted by >5% from tag
Any entity whose Flowgate(s) is impacted by >5% from the tag can have their Flowgate marked as market coordinated if requested. Any entity that has a Flowgate with >5% impact should be notified prior to the incorporation of the tag and given the opportunity to request market coordinated Flowgates.

To address the impact to these converted transactions, a process or situational awareness tool(s), such as an IDC display enhancement, may be used to assist non-market entities determine the impact of the market on a Flowgate in such situation.

Market entity must be able to accurately calculate market Flow impacts from the source
A market entity, including an external resource or collection of external resources, should only request a tag be ignored by the IDC and reported in market flows if the expanded market base case models or other arrangements are made to maintain accurate market flows. This is to ensure that the market entity reports a market flow that is reflective of the system conditions throughout the transfer path, inclusive of external areas on that path, and is able to achieve any relief obligation that may be assigned as a result of this arrangement. If the relief obligation is not met through an accepted congestion management process (market flow reallocation or transmission loading relief), manual RC intervention may apply.
## Appendix E: Revision History

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<th>Version</th>
<th>Date</th>
<th>Action</th>
<th>Change Tracking</th>
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<td>3</td>
<td>May 10, 2016</td>
<td>Replaced the Frequency Bias Setting section in Chapter 3 to reflect the frequency bias methodology used in BAL-003–1</td>
<td></td>
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<tr>
<td>4</td>
<td>May 27, 2019</td>
<td>NERC ORS/RS 3-year review and modifications</td>
<td>Updated Version</td>
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<td></td>
<td></td>
<td></td>
<td>• Addition of Appendix D NERC ORS Dynamic Tag Exclusion Process</td>
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<tr>
<td></td>
<td></td>
<td></td>
<td>• Updated Terms and definitions to match NERC Glossary</td>
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<td></td>
<td></td>
<td></td>
<td>• Minor grammar corrections</td>
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<tr>
<td></td>
<td></td>
<td></td>
<td>• Clarified responsibilities and coordination with RC and TOP</td>
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<td>• Updated Standard References</td>
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<td>• Clarified inclusion of dynamic transfers into congestion management</td>
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<td></td>
<td></td>
<td></td>
<td>• Added reference to <em>Balancing Authority Area Footprint Change Task Reference Document</em></td>
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<td>• Removed duplicate sections and sections covered in other referenced documents</td>
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<td>• Clarified and added coordination considerations</td>
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<td>• Updated Equation subscripts to match NERC Definitions</td>
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<tr>
<td></td>
<td></td>
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<td>• Simplified Tables and Examples</td>
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Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is divided into six RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Region while associated Transmission Owners/Operators participate in another.

<table>
<thead>
<tr>
<th>RE</th>
<th>Description</th>
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<tr>
<td>MRO</td>
<td>Midwest Reliability Organization</td>
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<td>Northeast Power Coordinating Council</td>
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<td>SERC</td>
<td>SERC Reliability Corporation</td>
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<td>Texas Reliability Entity</td>
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<tr>
<td>WECC</td>
<td>Western Electricity Coordinating Council</td>
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Overview

Purpose
The purpose of this document is to provide guidance and encourage consistency in the industry on the responsibilities, requirements, and expectations placed upon parties involved in establishing a Dynamic Transfer.

It is not within the scope of this reference document to require any organization to modify any existing Dynamic Transfers.

Terms

**Attaining Balancing Authority:** The Balancing Authority (BA) bringing generation or load into its effective control boundaries through Dynamic Transfer from the Native BA.

**Dynamic Transfer:** The provision of the real-time monitoring, telemetering, computer software, hardware, communications, engineering, energy accounting (including inadvertent interchange), and administration required to electronically move all or a portion of the real energy services associated with a generator or load out of one BA Area into another.

**Dynamic Transfer Signal:** The electronic signal used to implement a Pseudo-Tie or Dynamic Schedule using either a metered value or a calculated value.

**Dynamic Schedule or Dynamic Interchange Schedule:** A telemetered reading or value that is updated in real time and used as a schedule in the automatic generator control (AGC)/area control error (ACE) equation and the integrated value of which is treated as a schedule for interchange accounting purposes.

**Integration:** In the terms for Dynamic Schedule and Pseudo-Tie above means the value could be mathematically calculated or determined mechanically with a metering device and incorporated into the associated ACE calculations for the Attaining and Native BA.

**Native BA:** The BA from which a portion of its physically interconnected generation and/or load is assigned from its effective control boundaries through Dynamic Transfer to the Attaining BA.

**Attaining Reliability Coordinator:** The Reliability Coordinator (RC) for the Attaining BA.

**Native RC:** The RC for the Native BA.

**Pseudo-Tie:** A time-varying energy transfer that is updated in real-time and included in the actual net interchange term (NIA) in the same manner as a tie line in the affected BA’s reporting ACE equation (or alternate control processes).
Chapter 1: Dynamic Schedule versus Pseudo-Tie Fundamentals

The key difference between Pseudo-Ties and Dynamic Schedule is often viewed only as a system control issue. Discussions are typically limited to how the transfer is implemented in each BA’s ACE equations and in the associated energy accounting process. Pseudo-Ties are accounted for by all parties as actual interchange, and Dynamic Schedule are accounted for as scheduled interchange. However, there are other factors that must be considered when determining which type of Dynamic Transfer should be utilized for a given situation. The descriptions provided in this document are based on practical experience where Dynamic Transfers have been successfully implemented.

From a simple perspective, a Dynamic Schedule is a means of achieving a time-varying exchange of power where traditional block scheduling is not sufficient. Examples might be the partial or complete exchange of regulating obligations (see Appendix B: Supplemental Regulation Service as a Dynamic Schedule), the temporary provision of power under a reserve sharing agreement, or the exchange of power to serve a real-time demand signal.

Pseudo-Ties are typically, but not exclusively, used to represent Interconnections between two BAs at generation or load, similar to a physical tie line. These loads/generators, however, are at locations where no other physical connection exists between the load/generation and the power system network of the responsible Attaining BA’s traditional control boundaries defined by its physical tie lines. In the instance of a Pseudo-Tie, the operational and procedural responsibility\(^1\) for a source of load/generation is key and must be coordinated between all impacted BAs and RCs. In addition to system control responsibility that is traditionally considered, the responsibilities related to a Pseudo-Tie extend to such requirements as Disturbance Control Standard (DCS) recovery, load shedding, transmission and ancillary services, load forecasting, and system operating limit/Interconnection reliability operating limit mitigation, etc. associated with the load/generation.

Although both Pseudo-Ties and Dynamic Schedule involve time-varying quantities, unlike a Pseudo-Tie, a Dynamic Schedule may have no specific load/generation for which the Attaining BA is operationally or procedurally responsible.

The choice of a Pseudo-Tie versus a Dynamic Schedule can be adapted to suit any implementation between the Native and Attaining BAs as long as both BAs agree which one is responsible for each of the obligations associated with the load/generation. For example, a Pseudo-Tie would typically be used to represent a generator owned by an Attaining BA that is located within the physical tie line boundary of a Native BA. However, a Dynamic Schedule implementation can be used in each BA’s ACE equation as long as responsibility for obligations, such as recovery during a DCS event, are clearly understood and accepted by both BAs.

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\(^{1}\) Procedural responsibility refers to which BA area’s, RC area’s and/or which ERO Region’s requirements will apply to the generator or load.
Chapter 2: Dynamic Transfer Implementation Considerations

There are numerous considerations that the Attaining BA and the Native BA must address during the design and implementation of a Dynamic Transfer. This chapter identifies areas that should be discussed and agreed upon during the development of a new Dynamic Transfer. Dynamic Transfers can be used for, but not limited to, the following scenarios:

- To transfer all of, or a portion of, actual output of a specific generator to another BA in real-time.
- To provide the real-time power requirements for a load physically located in the Attaining BA from resources in the Native BA.
- To supply one or more interconnected operation services to generators and/or loads between the Native and Attaining BA.
- To provide a mechanism for reserve sharing.
- To provide supplemental regulation.

The particular Dynamic Transfer method to be utilized for a specific operating arrangement may be dependent on some or all of the following:

- The desired service(s) to be provided.
- The capability to capture the Dynamic Transfer in system models.
- Responsibility for forecasting load.
- Responsibility for providing unit commitment and maintenance information.
- Energy Management System (EMS) capability.

Each BA is obligated to fulfill its commitment to the Interconnection and not burden other BAs. The use of a Dynamic Transfer does not in any way diminish this responsibility. The following list of obligations should be discussed and accounted for in the design and implementation of a Dynamic Transfer:

- Before implementing the Dynamic Transfer, all parties to the Dynamic Transfer must agree on all implementation details.
- Any errors resulting from an improperly implemented or operated Dynamic Transfer (including inadvertent interchange accumulations) must be resolved between the involved parties.
- Dynamic Transfers must not include any control offsets that are not explicitly compliant with the requirements set forth in NERC Reliability Standards (e.g., unilateral inadvertent payback, Western Interconnection automatic time error control, etc.).
- Applicable tariff requirements of all involved or affected transmission providers and BAs must be met; this includes proper handling and accounting for energy losses.
- If the Dynamic Transfer includes a prearranged calculated assistance or distribution of responsibility between the Native BA and the Attaining BA for recovery from the loss of generation, then both BAs are responsible for ensuring that their respective DCS compliance requirements are met in accordance with NERC Standard BAL-002-3 — Disturbance Control Standard — Contingency Reserve for Recovery from a Balancing Contingency Event.

From a system modeling perspective, the assignment of load or generation into the control response of another BA must be appropriately captured in the reliability analysis tools. It is the obligation of each BA involved in the Dynamic...
Chapter 2: Dynamic Transfer Implementation Considerations

Transfer to ensure that the Dynamic Transfer of load or generation is coordinated with their TOP and RC so that the method of Dynamic Transfer can be considered in the system modeling of the generation or load affected and that the necessary data provision requirements are met. These provisions are listed as follows:

- To assure proper resource application, it is the responsibility of the Attaining BA dynamically transferring load into its effective boundaries through Pseudo-Ties to ensure that load forecasts and subsequent BA reporting reflect the load incorporated within its BA boundaries. Conversely, when a Dynamic Schedule is used to serve load within another BA area, the BA where the load is electrically connected (Native BA) must include that load in its BA load forecast and any subsequent reporting as needed.

- It is the responsibility of both the Native BA/TOP/RC and Attaining BA/TOP/RC to model any generation or load serving Dynamic Transfers in their respective power flow models, real-time assessments (RTAs) and modeled in the interchange distribution calculator (IDC) correctly. This modeling is required to ensure that affected BAs/TOPs/RCs study the generation or load regardless of the control boundary designations. This modeling also is necessary to ensure that each BA/TOP/RC can see the impact of the Dynamic Transfer on their systems.

- Dynamic Transfers must not affect reliability adversely. If the reliability impact of a Dynamic Transfer that has been implemented as a Pseudo-Tie cannot be addressed adequately without modeling it in the IDC or other applicable RTA system models that use scheduled values, then the Dynamic Transfer must be performed via a Dynamic Schedule.

For both Pseudo-Ties and Dynamic Schedule, the BAs shall adjust their frequency bias setting to account for the frequency bias characteristics of the loads and/or resources being assigned between BAs in accordance with the NERC process as referenced in *Balancing Authority Area Footprint Change Tasks Reference Document*.  

There are occasions when changes are needed to bias settings outside of the normal schedule. Examples are footprint changes between BAs and major changes in load or generation or the formation of new BAs. In such cases the changing BAs should reference the *Balancing Authority Area Footprint Change Tasks Reference Document* and work with their Regions and NERC to confirm appropriate changes to bias settings, FRO, CPS limits and Inadvertent Interchange balances.

The Native, Attaining, and Intermediate BAs must carefully coordinate many aspects related to Dynamic Transfers. Failure to do so may result in the creation of reliability problems for the Interconnection, may create after-the-fact energy accounting and billing problems, and may cause violations of industry standards. Below is a list of conditions that the participating BAs should ensure have been addressed prior to implementing a new Dynamic Transfer:

- Control offsets are compliant with applicable industry standards.
- Tariff requirements are met.
- DCS reporting requirements have been addressed.
- Transmission service has been addressed.
- Need for inclusion in reliability tools has been addressed.
- Transferred loads and/or generation are accounted for in energy dispatch.
- Transferred loads and/or generation are still included in relevant RTA tools.
- Frequency bias impacts have been addressed.
- Contingency plans for loss of Dynamic Transfer signal and telecommunications have been addressed.

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2 Insert Footnote when the document is posted
- Contingency plans for transmission constraints that prohibit the Dynamic Transfer.
- Industry compliance issues such as NERC and NAESB have been addressed.
- Energy accounting practices are consistent, including losses.
- The ancillary service provision has been addressed.
- Impact on reserve requirements have been addressed.
- Impact on under-frequency load shedding relays have been addressed.
- Dynamic Transfers must be included in congestion management.
- Primary and secondary telemetry methods for required data have been addressed.
- Ramp rates limitations have been addressed.
Table 2.1: Assignment of BA Obligations describes and outlines the obligations associated with the typical historical application of Pseudo-Ties and Dynamic Schedule related to many of the topics addressed above. In practical application, however, both the Native and Attaining BAs can agree to exchange the obligations from that shown in the Table 1. Additional coordination obligations with respect to pseudo ties and RC are listed in Chapter 4: Pseudo-Tie Implementation and Coordination.

<table>
<thead>
<tr>
<th>BA’s Obligation/modeling</th>
<th>Pseudo-Tie</th>
<th>Dynamic Schedule</th>
</tr>
</thead>
<tbody>
<tr>
<td>Generation planning and reporting and outage coordination</td>
<td>Attaining BA</td>
<td>Typically, Native BA but may be reassigned (wholly or a portion) to the Attaining BA</td>
</tr>
<tr>
<td>CPS and DCS recovery/reporting and RMS</td>
<td>Attaining BA</td>
<td>Attaining and/or Native BA (depending on agreements)</td>
</tr>
<tr>
<td>Operational responsibility</td>
<td>Attaining BA</td>
<td>Native BA</td>
</tr>
<tr>
<td>BA services</td>
<td>Attaining BA</td>
<td>Native BA</td>
</tr>
<tr>
<td>FERC Open Access Transmission Tariff (OATT) Schedules 3–6 and other ancillary services as required</td>
<td>Attaining/Native BA (as agreed)</td>
<td>Attaining/Native BA (as agreed)</td>
</tr>
<tr>
<td>Ancillary services associated with transmission FERC OATT Schedules 1–2 and other ancillary services as required</td>
<td>Attaining/Native BA (as agreed)</td>
<td>Attaining/Native BA (as agreed)</td>
</tr>
<tr>
<td>ACE frequency bias calc/setting</td>
<td>The Native and Attaining BAs shall adjust their frequency bias setting to account for the frequency bias characteristics of the loads and/or resources being assigned between BAs by the Pseudo-Tie</td>
<td>The Attaining BA should include the load from its Dynamic Schedule as a part of its forecast load to set frequency bias requirement. The Native BA should change its load used to set frequency bias setting by the same amount in the opposite direction.</td>
</tr>
<tr>
<td>Load forecasting and reporting</td>
<td>Attaining BA</td>
<td>Native BA</td>
</tr>
<tr>
<td>Manual load shedding during an Energy Emergency Alert</td>
<td>Attaining BA</td>
<td>Native BA</td>
</tr>
<tr>
<td>Coordination with RC for inclusion in congestion Management</td>
<td>Attaining BA if within one RC Both Attaining and Native BA if spanning multiple RC’s</td>
<td>Native BA if within one RC Both Attaining and Native BA if spanning multiple RC’s</td>
</tr>
</tbody>
</table>

Note: Table 2.1 contains the typical BA obligations that have been utilized throughout the industry for pseudo-ties and Dynamic Schedule. However, for any specific Dynamic Transfer implementation, both the Native and Attaining BAs can agree to exchange the obligations.
Chapter 3: Dynamic Schedule Implementation and Coordination

A Dynamic Schedule is implemented as an interchange transaction that is modified in real-time to transfer time-varying amounts of power between BAs. A Dynamic Schedule typically does not change a BA’s or RC’s operational responsibility (i.e., the Native BA/RC continues to exercise operational control over and provides basic BA/RC services to the dynamically scheduled resources).

Dynamic Schedule are to be accounted for as interchange schedules by the source, sink, and contract intermediary BAs both in their respective ACE equations and throughout all of their energy accounting processes. Requirements to incorporate a Dynamic Schedule into the contract intermediary BA’s ACE are subject to regional procedures.

All Dynamic Schedule used for supplemental regulation or to assign the control of generation, loads, or resources from one BA to another must meet the following requirements:

- **Telemetry:** Appropriate telemetry must be in place and incorporated by all affected BAs in accordance with all NERC Reliability Standards, especially the Disturbance Control Performance standard.

- **Transmission Service:** Prior to implementation of the Dynamic Schedule of load or generation, all applicable NERC interchange Reliability Standards need to be met, including ancillary services and provision of losses.

- **System Modeling:** When a Dynamic Schedule is used to serve load within another BA area, the BA where the load is electrically connected (Native BA) must include this load in its BA load forecast for both energy dispatch and RTA and any subsequent reporting as needed. This is necessary because the system models must adequately capture the projected demand on the system (load forecast) and the projected supply (provided by the electronic tagging system).

- **Dynamic Schedule Coordination and Scheduling:** The implementation of a Dynamic Schedule must be through the use of an interchange transaction between BAs. As such, all Dynamic Schedule shall be implemented in accordance with NERC reliability standards. All Dynamic Schedule impacts are reflected in market flow calculations for entities that report market flows unless that entity has requested an exemption and that exemption has been requested and approved as specified in: Appendix A: ACE Equation Implications of Dynamic Transfers.

Energy exchanged between the source, sink, and intermediary BAs as a Dynamic Schedule is the metered or calculated (obtained by the integration of the Dynamic Schedule signal) energy for the loads and/or resources. Agreements must be in place with the applicable transmission providers to address the physical or financial provision of transmission losses.

The Native BA must ensure that agreements are in place that define the responsibility for providing applicable ancillary/interconnected operations services.

If the power flows associated with the Dynamic Schedule are expected to be bi-directional, two separate Dynamic Schedule are required (each schedule to be implemented as unidirectional following the “gen-to-load” direction convention). This expectation is a result of the fact that transmission service would be required for the Dynamic Schedule and most often import and export transmission services are provided as separate reservations.
• **Contingency Response:** Before implementation of the Dynamic Schedule, the involved BAs shall agree on a plan. The plan should ensure that operating practices have been established:

  ▪ To operate during a loss of the Dynamic Schedule telemetry signal such that all involved BAs are using the same value (including periods of time when the interconnection between them is unavailable). The BAs may agree to hold the last known good value, use an average load profile value, or have one party provide the other with a manual override value at some acceptable frequency of update.

  ▪ To serve the load during system conditions which prevent delivery of the Dynamic Schedule from the generation to the load.

  ▪ To re-dispatch the generation that had served the dynamically scheduled load prior to the system conditions which prevent delivery from the generation to the load.

• Compliance with NERC Reliability Standards.

The implementation of a Dynamic Schedule may confer upon the Attaining BA additional responsibilities for compliance with NERC Reliability Standards for the load or generation that has been transferred.
Chapter 4: Pseudo-Tie Implementation and Coordination

Pseudo-Ties are often employed to assign generators, loads, or both from the BA to which they are physically connected to a BA that has effective operational control. Thus, Pseudo-Ties often provide for a change of BA operational responsibility from the Native to the Attaining BA and make the Attaining BA provider of BA services at the same time. In practice, Pseudo-Ties may be implemented based upon metered or calculated values. All BAs involved account for power exchange and associated transmission losses as actual interchange between the BAs in their ACE equations and throughout all of their energy accounting processes.

All Pseudo-Ties used to assign generation, loads, or resources from the Native BA to the Attaining BA must meet the following requirements:

- **Telemetry:** Prior to implementation of the Pseudo-Tie transfer of load or generation, all applicable NERC Reliability Standards need to be met, including:
  - common metering points
  - adequate communications infrastructure

  The requirement for common metering points and adequate communications infrastructure does not imply specific ownership of telemetry devices.

- **Transmission Service:** Prior to implementation of the Pseudo-Tie transfer of load or generation, each involved BA shall ensure that the Dynamic Transfer is implemented such that the tariff requirements of the applicable transmission provider(s), including applicable ancillary services and provision of losses, are met.

  If transmission service between the Native and Attaining BAs is curtailed, then the allowable range of the magnitude of the Pseudo-Ties between them must be limited accordingly to these constraints.

  Agreements must be in place with the applicable transmission providers to address the physical and/or financial provision of transmission losses.

- **System Modeling:** The Attaining BA dynamically transferring load into its effective boundaries through a Pseudo-Tie shall ensure that load forecasts used for energy dispatch and subsequent BA reporting reflect the load incorporated within its BA boundaries. The Native BA would continue to consider this load in load forecasts used for its RTA.

  If the reliability impact of the Pseudo-Tie cannot be accurately captured in the IDC and/or any other RTA system models of the reliability entities impacted by the Dynamic Transfer, then the Dynamic Transfer must be implemented as a Dynamic Schedule.

- **Pseudo-Tie Coordination and Scheduling:** Subsequent to moving load or resources into an Attaining BA through Pseudo-Tie transfers, all interchange transactions or other energy transfers to the loads or from the resources must be coordinated among the Attaining intermediary and Native BAs in accordance with the NERC Reliability Standards.
  - The Attaining BA assumes responsibility for BA services required by the assigned loads and/or resources. The Attaining BA assumes all regulation, contingency reserves, and other BA responsibilities for the loads and/or resources in question.
  - Energy exchanged between the Native and Attaining BAs by the Pseudo-Tie method is accounted for by the associated revenue meter reading (if such meter exists at the dynamically assigned resource or load) or energy calculated by integrating the associated telemetered real-time signal.
• **Contingency Response:** Before implementation of the Pseudo-Tie transfer, the involved BAs shall agree on a plan:
  - To operate during a loss of the Pseudo-Tie transfer telemetry signal such that all involved BAs are using the same value, including periods of time when the interconnection between them is unavailable. The BAs may agree to hold the last known good value, use an average load profile value, or have one party provide the other with a manual override value at some acceptable frequency of update.
  - To serve the load during system conditions that prevent delivery of the Pseudo-Tie transfer from the generation to the load.
  - To re-dispatch the generation that had served the Pseudo-Tie transfer load prior to the system conditions which prevent delivery from the generation to the load.

• **Compliance with NERC Operating Standards:** The implementation of a Pseudo-Tie transfers may confer upon the Attaining BA additional responsibilities for compliance with NERC Reliability Standards for the load or generation that has been transferred.

In addition to the BA to BA coordination requirements listed above, the following items must also be addressed to ensure proper coordination between all impacted BAs and RCs:

• **BA and RC interaction during approval process:** Attaining, Intermediate, and Native BAs should be part of the approval process for implementing Pseudo-Ties as well as Attaining and Native RCs. Attaining BA is defined as a BA that brings generation or load into its effective control boundaries through a Dynamic Transfer from the Native BA. Native BA is defined as BA from which a portion of its physically interconnected generation and/or load is transferred from its effective control boundaries to the Attaining BA through a Dynamic Transfer.
  - Requirements to submit outages for Pseudo-Tied equipment as well as other RC responsibilities (i.e. next day studies, etc.) will be coordinated between the Attaining and Native RCs.
  - RC responsibilities for the Pseudo-Ties shall be agreed upon between involved parties at time of registration of the arrangement. Unit commitment/dispatch plan information for up to seven days out should be made available to the Native RC and interconnected TOP upon request.
  - Transmission service that uses Pseudo-Ties should be accurately reflected in the available Flowgate capability or available transfer capability calculations.
  - Prior to the implementation of new Pseudo-Ties or changes to existing Pseudo-Ties, both the Attaining and Native RCs should have a mutual understanding how operational issues related to the Pseudo-Ties will be administered. These discussions should include designation of each RC responsibilities for the Pseudo-Tied facility and how reliability-related changes to the Pseudo-Tied transaction will be implemented.

• **Firm transmission should be used for the entire path for the Eastern Interconnection:** For proper allocation of network and Native load based on current generation-to-load calculation in the IDC, a Pseudo-Tie must use firm transmission service. Transmission service should be studied with the points of receipt and points of delivery reflecting the specific location of generator or load being Pseudo-Tied. If a transmission service provider offers conditional firm transmission service based on their tariff, the service must be coordinated with their Native RC to ensure the accuracy of their congestion management.
If firm transmission service is not used for all portion of the path between the Native and Attaining BAs, the Attaining BA must set the pseudo tied generator’s priority to non-firm to be consistent with the Parallel Flow Visualization (PFV) requirements set forth by NAESB.³

- **Native RC should have authority to direct the generator/load, in order to address local area issues**: The Native RC/TOP should coordinate with the Attaining BA/RC of a Pseudo-Tied generator to dispatch the Pseudo-Tied generator to a level that is deemed reliable to manage congestion in a local area issue. The Native RC/TOP may need to request commitment modifications to manage congestion in a local area.

The Native RC and/or TOP should retain the right to issue operating instructions to the Pseudo-Tied unit to modify unit output if needed to resolve a local transmission reliability issue. If there are conflicts in operating instructions between the Native RC/TOP and the Attaining RC/TOP of a Pseudo-Tied generator, the Native RC/TOP and Attaining RC/TOP shall work to resolve the conflict with the Native RC/TOP having priority authorization to resolve the reliability issue.

- **The market entity must be able to accurately calculate market flow impacts from the source**: The market entity, including an external resource/load or collection thereof, should only implement a Pseudo-Tie if the market entity’s real-time network model is expanded to at least the location of the source/sink of the Pseudo-Tie and its surrounding buses. This is to ensure that the market entity reports market flow that is reflective of the system conditions throughout the path of the transfer inclusive of external areas on that path and is able to achieve any relief obligation that may be assigned as result of this arrangement. If relief obligation is not met through an accepted congestion management (market flow reallocation or transmission loading relief), manual RC actions may apply.

The attaining entity must ensure sufficient detail in the IDC model to calculate generation-to-load impacts from the source:

An entity whose Pseudo-Tie is not being tagged, including an external resource/load or collection thereof, must ensure there is sufficient detail in the IDC model to calculate the generation-to-load impacts that are reflective of the system conditions throughout the path of the transfer that is inclusive of external areas on that path. The RC should ensure any relief obligation that may be assigned as result of this arrangement are realistic. If relief obligation is not met through TLR, a manual RC intervention may apply.

- **Notification to the industry stakeholders**: A notification of future requests for Pseudo-Ties should be made to the NERC Operating Reliability Subcommittee (ORS) by the Attaining RC. The Attaining RC will confirm how these guidelines will be met before implementation of the Pseudo-Ties. To make this process manageable, only Pseudo-Tie notifications where the resource capacity exceeds 20 MW at a single bus, or where the amount of peak load exceeds 50 MW at a single bus, will need to be made to the NERC ORS. The Attaining RC notifies the NERC ORS of such Pseudo-Tie changes to improve situational awareness, and the NERC ORS will not be providing approval or denial of such changes.

Sufficient notice of a Pseudo-Tie addition needs to be given to affected BAs, TOPS, and RCs to allow changes to be made to their EMS and accounting systems when a Pseudo-Tie is added or removed. This work can take several months to complete.

- **Pseudo-Tie removal**: There are no similar requirements to notify NERC ORS under this guideline when a Pseudo-Tie is removed that results in returning the resource/load back to its Native BA/RC.

Sufficient notice of a Pseudo-Tie removal needs to be given to affected BAs, TOPS, and RCs to allow changes to be made to their EMS and accounting systems when a Pseudo-Tie is added or removed. This work can take several months to complete.

³ [https://www.naesb.org/pdf4/weq_bps011812w7.docx](https://www.naesb.org/pdf4/weq_bps011812w7.docx)
Appendix A: ACE Equation Implications of Dynamic Transfers

A Balancing Authority’s internal obligations, along with the small additional “bias” obligation to maintain frequency, is represented via a real-time value called ACE, estimated in MW. Dynamic Transfers have an impact on the calculation of ACE and should be included into the respective ACE calculations as part of implementation. This appendix provides the base ACE equation along with examples of how to adjust the base a BA’s ACE equation to support the implementation of Dynamic Transfers.

\[
ACE = \left[ \text{net actual interchange} - \text{net schedule interchange} \right] - 10B (F_A - F_S) - I_{ME} + I_{ATEC}^4
\]

Where:

**Net Actual Interchange (NI\_a)**

Affected by Pseudo-Ties/AGC interchanges

\[
NI_a = (\text{SUM of Tie Lines}) + (\text{SUM of Pseudo-Ties})
\]

\[
NI_a = (NI_{a}) + (NI_{APTGE} - NI_{APTGI} - NI_{APTLE} + NI_{APTLI} + NI_{ARSE} - NI_{ARSI})
\]

Where:

\[
NI_{a} = \text{Net sum of tie line flows}
\]

\[
NI_{APTGE} = \text{Sum of AGC Pseudo-Tie interchange generation external to the Attaining BA.}
\]

\[
NI_{APTGI} = \text{Sum of AGC Pseudo-Tie interchange generation internal to the BA (Native BA).}
\]

\[
NI_{APTLE} = \text{Sum of AGC Pseudo-Tie interchange load external to the BA (Attaining BA).}
\]

\[
NI_{APTLI} = \text{Sum of AGC Pseudo-Tie interchange load internal to the BA (Native BA).}
\]

\[
NI_{ARSE} = \text{Supplemental regulation service external to the BA (BA purchasing the supplemental regulation service) via Pseudo-Tie. See Appendix C.}
\]

\[
NI_{ARSI} = \text{Supplemental regulation service internal to the BA (BA selling the supplemental regulation service) via Pseudo-Tie. See Appendix C.}
\]

And where values for all generation and load terms are assumed to be positive quantities.

---

^4 I_{ATEC} is specifically used in the Western Interconnection
Appendix A: ACE Equation Implications of Dynamic Transfers

Net Scheduled Interchange (NIS)

Affected by Dynamic Schedule and supplemental regulation services.

\[
\text{NIS} = (\text{SUM of non-dynamically scheduled transactions}) + (\text{SUM of Dynamic Schedule})
\]

\[
\text{NIS} = (\text{NIs}) + (-\text{NISDSGE} + \text{NISDSGI} + \text{NISDSLE} - \text{NISDSLI} - \text{NISRSE} + \text{NISRSE})
\]

Where:

- \(\text{NIs}\) = Net sum of non-dynamically scheduled transactions
- \(\text{NISDSGE}\) = Sum of dynamically scheduled generation external to the Attaining BA
- \(\text{NISDSGI}\) = Sum of dynamically scheduled generation internal to the Native BA
- \(\text{NISDSLE}\) = Sum of dynamically scheduled load external to the Attaining BA
- \(\text{NISDSLI}\) = Sum of dynamically scheduled load internal to the Native BA
- \(\text{NISRSE}\) = Supplemental regulation service external to the BA (BA purchasing the supplemental regulation service). See Appendix B
- \(\text{NISRSE}\) = Supplemental regulation service internal to the BA (BA selling the supplemental regulation service). See Appendix B

Where values for all generation and load terms are assumed to be positive quantities.

Terms Unaffected by Dynamic Transfers

- \(B\) = BA frequency bias
- \(F_A\) = actual frequency
- \(F_S\) = scheduled frequency
- \(I_{ME}\) = meter error correction
- \(I_{ATEC}\) = automatic time error correction (If implemented within Interconnection)

\[
\text{ACE} = \left\{ (\text{NIs}) + (\text{NISAPTGE} - \text{NISAPTGI} - \text{NISAPTLE} + \text{NISAPTLI} + \text{NISRSE} - \text{NISRSE}) \right\} - \left\{ (\text{NIs}) + (-\text{NISDSGE} + \text{NISDSGI} + \text{NISDSLE} - \text{NISDSLI} - \text{NISRSE} + \text{NISRSE}) \right\} - 10B (F_A - F_S) - I_{ME} + I_{ATEC}
\]
ACE Equation Component Tables
The following tables depict the specific ACE equation components that should be included by each BA if implementing Dynamic Transfers.

**Application of Pseudo-Ties in ACE by BAs**
Application of Pseudo-Tie between adjacent BAs (BA\text{A} and BA\text{B} are adjacent)

<table>
<thead>
<tr>
<th>Pseudo-Tie Transfer</th>
<th>Path</th>
<th>BA\text{A} ACE Inclusions</th>
<th>BA\text{B} ACE Inclusions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Generator from BA\text{A} to BA\text{B}</td>
<td>BA\text{A} -&gt; BA\text{B}</td>
<td>NI\text{APTGI}</td>
<td>NI\text{APTGE}</td>
</tr>
<tr>
<td>Load from BA\text{A} to BA\text{B}</td>
<td>BA\text{A} -&gt; BA\text{B}</td>
<td>NI\text{APTLI}</td>
<td>NI\text{APTLI}</td>
</tr>
</tbody>
</table>

Application of Pseudo-Tie between two BAs including an Intermediate BA (BA\text{D} and BA\text{F} are non-adjacent and flow traverses BA\text{E})

<table>
<thead>
<tr>
<th>Pseudo-Tie Transfer</th>
<th>Path</th>
<th>BA\text{D} ACE Inclusions</th>
<th>BA\text{E} ACE Inclusions</th>
<th>BA\text{F} ACE Inclusions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Generator from BA\text{D} to BA\text{F}</td>
<td>BA\text{D} -&gt; BA\text{E} -&gt; BA\text{F}</td>
<td>NI\text{APTGI}</td>
<td>NI\text{APTGE}</td>
<td>NI\text{APTGE}</td>
</tr>
<tr>
<td>Load from BA\text{A} to BA\text{B}</td>
<td>BA\text{A} -&gt; BA\text{B}</td>
<td>NI\text{APTLI}</td>
<td>NI\text{APTLI}</td>
<td>NI\text{APTLI}</td>
</tr>
</tbody>
</table>

**Application of Dynamic Schedule in ACE by BAs**
Application of Dynamic Schedule between adjacent BAs

<table>
<thead>
<tr>
<th>Dynamic Schedule Transfer</th>
<th>Path</th>
<th>BA\text{A} ACE Inclusions</th>
<th>BA\text{B} ACE Inclusions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Generator from BA\text{A} to BA\text{B}</td>
<td>BA\text{A} -&gt; BA\text{B}</td>
<td>NI\text{SDSGI}</td>
<td>NI\text{SDSGE}</td>
</tr>
<tr>
<td>Load from BA\text{A} to BA\text{B}</td>
<td>BA\text{A} -&gt; BA\text{B}</td>
<td>NI\text{SDSUI}</td>
<td>NI\text{SDSLE}</td>
</tr>
</tbody>
</table>

Application of Dynamic Schedule between two BAs, including an Intermediate BA (BA\text{D} and BA\text{F} are non-adjacent and flow traverses BA\text{E})

<table>
<thead>
<tr>
<th>Dynamic Schedule Transfer</th>
<th>Path</th>
<th>BA\text{D} ACE Inclusions</th>
<th>BA\text{E} ACE Inclusions</th>
<th>BA\text{F} ACE Inclusions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Generator from BA\text{D} to BA\text{F}</td>
<td>BA\text{D} -&gt; BA\text{E} -&gt; BA\text{F}</td>
<td>NI\text{SDSGI}</td>
<td>NI\text{SDSGE}</td>
<td>NI\text{SDSGE}</td>
</tr>
<tr>
<td>Load from BA\text{A} to BA\text{B}</td>
<td>BA\text{D} -&gt; BA\text{E} -&gt; BA\text{F}</td>
<td>NI\text{SDSUI}</td>
<td>NI\text{SDSLE}</td>
<td>NI\text{SDSLE}</td>
</tr>
</tbody>
</table>
**Dynamic Transfer Numeric Examples**

Assume: Net sum of tie flows = 0, Net sum of non-dynamically scheduled transactions = 0, $F_S = F_A$, and $I_{ME} = 0$

In **Figure A.1** example, BA_A will become the Attaining BA for load Y and generator Z. Similarly, BA_B will become the Attaining BA for load X and generator W.

**Using Pseudo-Ties**

Using **Table A.1** to obtain the correct net actual interchange terms for the Pseudo-Ties, the ACE equation becomes the following:

$$ACE_{BA_A} = NIA - NIS = (NIA + NI_{APTGI(Z)} - NI_{APTGE(W)} - NI_{APTGI(Y)} + NI_{APTGE(X)}) - NIS = (NI_a + Gen Z - Gen W - Load Y + Load X) - NIS$$

Substituting the values in the example as positive quantities, the equation becomes as follows:

$$ACE_{BA_A} = (0 + 200 - 100 - 75 + 50) - 0 = 75$$

**Using Dynamic Schedule**

Using **Table A.3** to obtain the correct net scheduled interchange terms for the Dynamic Schedule, the ACE equation for BA_A becomes the following:

$$ACE_{BA_A} = NIA - NIS = NIA - (NIS - NI_{SDSGE(Z)} + NI_{SDSGE(W)} + NI_{SDSLI(Y)} - NI_{SDSLI(X)}) = NIA - (NIS - Gen Z + Gen W - Load Y - Load X)$$

Substituting the values in the example as positive quantities, the equation becomes as follows:

$$ACE_{BA_A} = 0 - (0 - 200 + 100 + 75 - 50) = 0 - (-75) = 75$$

**Using both Pseudo-Ties and Dynamic Schedule**

Assume that the generation will be modeled as Dynamic Schedule and the loads as Pseudo-Ties. Using **Table A.1** and **Table A.3** to obtain the correct net scheduled interchange and net actual interchange terms for the Dynamic Transfers, the ACE equation for BA West becomes as follows:

$$ACE_{BA_A} = NIA - NIS = (NIA - NI_{APTTLI(Y)} + NI_{APTLE(X)}) - (NIS - NI_{SDSGE(Z)} + NI_{SDSGI(W)}) = (NI_a - Load Y + Load X) - (NIS - Gen Z + Gen W)$$

Substituting the values in the example as positive quantities, the equation becomes as follows:

$$ACE_{BA_A} = (0 - 75 + 50) - (0 - 200 + 100) = (-25) - (-100) = 75$$

**Note:** In all cases, the ACE value is the same regardless of the Dynamic Transfer method used.
Appendix B: Supplemental Regulation Service as a Dynamic Schedule

Supplemental regulation service is when one BA provides part of the regulation requirements of another BA. The BAs implement a Dynamic Schedule that incorporates the calculated portion of the ACE signal that has been agreed upon between them. This is accomplished by adding another component to the scheduled interchange ACE equation for both BAs. Care should be taken to maintain the proper sign convention to ensure proper control with the BA purchasing regulation service subtracting the supplemental regulation service from the scheduling component of their ACE while the BA providing the service adds it to the scheduling component of their ACE.

If the supplemental regulation service includes a calculated assistance between the Native BA and the Attaining BA for recovery from the loss of generation, then both BAs are responsible for assuring that DCS compliance reporting requirements are met in accordance with NERC Standard BAL-002-3 — Disturbance Control Standard – Contingency Reserve for Recovery from Balancing Contingency Event.5

ACE Equation Modifications

The ACE equation modifications required for supplemental regulation service are as follows:

Typically:

\[ \text{ACE} = (N_{IA} - N_{IS}) - 10B (F_A - F_S) - I_{ME} \]

Where:

- \( N_{IA} \) = net actual interchange
- \( N_{IS} \) = net scheduled interchange
- \( B \) = BA frequency bias
- \( F_A \) = actual frequency
- \( F_S \) = scheduled frequency
- \( I_{ME} \) = meter error correction

For a Dynamic Schedule the \( N_{IA} \) remains unchanged, but to implement supplemental regulation service, the \( N_{IS} \) term becomes as follows:

\[ N_{IS} = N_{IS} - N_{SDSGE} + N_{SDSGI} + N_{SDSL} - N_{SRSE} + N_{SRSI} \]

Where:

- \( N_{S} \) = Net sum of non-dynamically scheduled transactions
- \( N_{SDSGE} \) = sum of dynamically scheduled generation external to the BA (Attaining BA)
- \( N_{SDSGI} \) = sum of dynamically scheduled generation internal to the BA (Native BA)
- \( N_{SDSL} \) = sum of dynamically scheduled load external to the BA (Attaining BA)
- \( N_{SRSE} \) = Supplemental regulation service external to the BA (BA purchasing the supplemental regulation service)
- \( N_{SRSI} \) = Supplemental regulation service internal to the BA (BA selling the supplemental regulation Service)

And where supplemental regulation service for an overgeneration condition is assumed to be negative and for under generation it is positive to achieve the desired effect via \( N_{S} \) on ACE as described in the “NAESB WEQ Area Control Error (ACE) Equation Special Cases Standards - WEQBPS – 003-000”6

5 NERC Standard BAL-002-3 — Disturbance Control Standard – Contingency Reserve for Recovery from Balancing Contingency Event
6 https://www.naesb.org/pdf2/weg_bklet_011505_ace_mc.pdf
Supplemental Regulation as Dynamic Schedule - Numeric Example

Assume: Net sum of tie flows = 0, net sum of non-dynamically scheduled transactions = 20 MW from BA_WestA to BA_EastB, $F_S = F_A$, and $I_{ME} = 0$

In Figure B.1 example, BA_A is purchasing 15 MW of supplemental regulation. Similarly, BA_B is selling 15 MW of supplemental regulation.

Using the correct net scheduled interchange terms for supplemental regulation as a Dynamic Schedule, the ACE equation for BA_A becomes as follows:

$$ACE_{BA_A} = NI_A - NI_b = NI_A - (NI_b - NI_{SDSGE} + NI_{SDSGI} + NI_{SDGGE} - NI_{SDSLU} - NI_{SRSE} + NI_{SRSI})$$

simplifying for applicable terms for this example yields, $= NI_A - (NI_b - NI_{SRSE})$

Since purchaser BA_A is in an under-generating condition in this example, the supplemental regulation term is positive and substitution in the equation becomes:

$$ACE_{BA_A} = 0 - (20 - 15) = 0 - 5 = -5$$

Similarly, the ACE equation for BA East becomes:

$$ACE_{BA_B} = NI_A - NI_b = NI_A - (NI_b - NI_{SDSGE} + NI_{SDSGI} + NI_{SDGGE} - NI_{SDSLU} - NI_{SRSE} + NI_{SRSI})$$

simplifying for applicable terms for this example yields, $= NI_A - (NI_b + NI_{SRSI})$

Again, since purchaser BA_B is in an under generating condition in this example, the supplemental regulation term is positive and substitution in the equation becomes as follows:

$$ACE_{BA_B} = 0 - (−20 + 15) = 0 - (−5) = 5$$
Appendix C: Supplemental Regulation Service as a Pseudo-Tie

Supplemental regulation service is when one BA provides all or part of the regulation requirements of another BA. The BAs implement a Pseudo-Tie that incorporates the calculated portion of the ACE signal that has been agreed upon between them. This is accomplished by adding another component to the actual interchange component of the ACE equation for both BAs. Care should be taken to maintain the proper sign convention to ensure proper control.

If the supplemental regulation service includes a calculated assistance between the Native BA and the Attaining BA for recovery from the loss of generation, then both BAs are responsible for assuring that DCS compliance reporting requirements are met in accordance with NERC Standard BAL-002-3 — Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event.7

ACE Equation Modifications

The ACE equation modifications required for supplemental regulation service are as follows:

Typically:

\[ \text{ACE} = (\text{NI}_A - \text{NI}_S) - 10B (\text{F}_A - \text{F}_S) - \text{IME} \]

Where:

- \( \text{NI}_A \) = net actual interchange
- \( \text{NI}_S \) = net scheduled interchange
- \( B \) = BA frequency bias
- \( \text{F}_A \) = actual frequency
- \( \text{F}_S \) = scheduled frequency
- \( \text{IME} \) = meter error correction

For a Pseudo-Tie with supplemental regulation, the \( \text{NI}_S \) remains unchanged, but the \( \text{NI}_A \) term becomes as follows:

\[ \text{NI}_A = \text{NI}_A + (\text{NI}_{APTGE} - \text{NI}_{APTGI} + \text{NI}_{APTLI} + \text{NARSE} - \text{NARSI}) \]

Where:

- \( \text{NI}_A \) = Net sum of tie line flows.
- \( \text{NI}_{APTGE} \) = sum of AGC interchange generation external to the Attaining BA.
- \( \text{NI}_{APTGI} \) = sum of AGC interchange generation internal to the BA (Native BA).
- \( \text{NI}_{APTLI} \) = sum of AGC interchange load internal to the BA (Native BA).
- \( \text{NI}_{ARSE} \) = supplemental regulation service external to the BA (BA purchasing the supplemental regulation service) via Pseudo-Tie.
- \( \text{NI}_{ARSI} \) = supplemental regulation service internal to the BA (BA selling the supplemental regulation service) via Pseudo-Tie.

As with Dynamic Schedule for both the purchasing and selling BAs, supplemental service being provided to alleviate overgeneration has a negative sign while supplemental service being provided to alleviate under generation has a positive sign.

---

7 NERC Standard BAL-002-3 — Disturbance Control Standard – Contingency Reserve for Recovery from Balancing Contingency Event
Supplemental Regulation as Pseudo-Tie - Numeric Example

Assume:

- Net sum of tie flows = 0,
- Net sum of non-dynamically scheduled transactions = 20 MW from BA_A-West to BA_B-East,
- $F_S = F_A$ and $I_{ME} = 0$

In Figure C.1 example, BA_A will become the BA purchasing 15 MW of supplemental regulation. Similarly, BA_B will become the BA selling 15 MW of supplemental regulation.

Using the correct net actual interchange terms for supplemental regulation as a Pseudo-Tie, the ACE equation for BA_A becomes as follows:

$$ACE\ BA_A = NI_A - NI_S = (NI_a + NI_{APTGE} - NI_{APTGI} - NI_{APTLE} + NI_{APTLI} + NARSE - NARSI) - NI_S,$$

simplifying for applicable terms for this example yields,

$$ACE\ BA_A = (NI_a + NARSE) - NI_S$$

Since purchaser BA_A is in an under-generating condition in this example, the supplemental regulation term is positive and substitution in the equation becomes as follows:

$$ACE\ BA_A = (0 + 15) - 20 = 15 - 20 = -5$$

Similarly, the ACE equation for BA-East becomes:

As follows:

$$ACE\ BA_B = NI_A - NI_S = (NI_a + NI_{APTGE} - NI_{APTGI} - NI_{APTLE} + NI_{APTLI} + NARSE - NARSI) - NI_S,$$

simplifying for applicable terms for this example yields,

$$ACE\ BA_B = (NI_a - NARSI) - NI_S$$

Again, since purchaser BA_A is in an under generating condition in this example, the supplemental regulation term is positive and substitution in the equation becomes as follows:

$$ACE\ BA_B = (0 - 15) - (-20) = -15 + 20 = 5$$
Appendix D: Dynamic Tag Exclusion Process

Over the years, numerous requests were made to the Interchange Distribution Calculator Working Group (IDCWG) and the ORS in order to accommodate special arrangements for different BAs to support congestion management actions that need to be reflected in the IDC, such as the exclusion of tags with a specific source and sink combination due to the MW impact being included in different curtailable products. These requests have been, up to this point, handled on a case-by-case basis as there is not a consistent process or set of guidelines to ensure such arrangements are implemented with no degradation to reliability or change in equity status for the products.

The ORS created a Task Force to work with the IDCWG to develop a process for the exclusion of tags.

**Applicability**
This process is applicable to RCs and BAs that manage dynamic tags.

**Dynamic Tag Exclusion Management**

**Approval process**
The NERC ORS is not tasked or qualified to approve equity-related issues. The ORS is tasked with ensuring reliability is maintained. Therefore, prior to requesting NERC ORS approval to allow the IDC to ignore a Dynamic Schedule tag, the requesting entity is expected to coordinate with NAESB BPS and/or applicable congestion management oversight policy committees to ensure no equity concerns exist. In addition, the requesting entity must also have approval from the IDCWG to ensure no technical concerns exist. Then the entity may request approval from the ORS.

**Requirements for incorporating Dynamic Schedule into Market Flow**
If the tagged Dynamic Schedule MW are converted to market flow and ignored by the IDC, the market flow MW representing the converted tags shall have a priority that is no higher than it would have been if the tag was not ignored.

For nonmarket entities, an otherwise tagged MW shall preserve the priority of the transaction if converted to a product not requiring a tag (gen-to-load).

**Entity with Flowgates impacted by >5% from tag**
Any entity that has Flowgates that are impacted by >5% from the tag can have their Flowgate marked as market coordinated if requested. Any entity that has a Flowgate with >5% impact should be notified prior to the incorporation of the tag and given the opportunity to request market coordinated Flowgates.

To address the impact to these converted transactions, a process or situational awareness tool, such as an IDC display enhancement, may be used to assist non-market entities to determine the impact of the market on a Flowgate in such a situation.

**Market entity must be able to accurately calculate market Flow impacts from the source**
A market entity, including an external resource or collection of external resources, should only request a tag be ignored by the IDC and reported in market flows if the expanded market base case models or other arrangements are made to maintain accurate market flows. This is to ensure that the market entity reports a market flow that is reflective of the system conditions throughout the transfer path, inclusive of external areas on that path, and is able to achieve any relief obligation that may be assigned as a result of this arrangement. If the relief obligation is not met through an accepted congestion management process (market flow reallocation or transmission loading relief), manual RC intervention may apply.
# Appendix E: Revision History

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<th>Date</th>
<th>Action</th>
<th>Change Tracking</th>
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<tr>
<td>3</td>
<td>May 10, 2016</td>
<td>Replaced the Frequency Bias Setting section in Chapter 3 to reflect the frequency bias methodology used in BAL-003--1</td>
<td></td>
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<tr>
<td>4</td>
<td>May 27, 2019</td>
<td>NERC ORS/RS 3-year review and modifications</td>
<td>• Updated Version</td>
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<tr>
<td></td>
<td></td>
<td></td>
<td>• Addition of Appendix D NERC ORS Dynamic Tag Exclusion Process</td>
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<tr>
<td></td>
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<td></td>
<td>• Updated Terms and definitions to match NERC Glossary</td>
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<td></td>
<td></td>
<td></td>
<td>• Minor grammar corrections</td>
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<tr>
<td></td>
<td></td>
<td></td>
<td>• Clarified responsibilities and coordination with RC and TOP</td>
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<tr>
<td></td>
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<td></td>
<td>• Updated Standard References</td>
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<tr>
<td></td>
<td></td>
<td></td>
<td>• Clarified inclusion of Dynamic Transfers into congestion management</td>
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<tr>
<td></td>
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<td></td>
<td>• Added reference to <em>Balancing Authority Area Footprint Change Task Reference Document</em></td>
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<tr>
<td></td>
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<td></td>
<td>• Removed duplicate sections and sections covered in other referenced documents</td>
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<tr>
<td></td>
<td></td>
<td></td>
<td>• Clarified and Added coordination considerations</td>
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<tr>
<td></td>
<td></td>
<td></td>
<td>• Updated Equation subscripts to match NERC Definitions</td>
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<tr>
<td></td>
<td></td>
<td></td>
<td>• Simplified Tables and Examples</td>
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</tbody>
</table>
Midcontinent Independent System Operator

Regional Transmission Organization (RTO) Reliability Plan

September 1, 2019
## Document Change History

<table>
<thead>
<tr>
<th>Issue</th>
<th>Reason for Issue</th>
<th>Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Version 0</td>
<td>Reformatted and updated MISO RTO Reliability Plan to meet the terms of NERC Operating Standards as approved by NERC.</td>
<td>11/3/05</td>
</tr>
<tr>
<td>Version 1</td>
<td>Removed LGEE and DEVI from Reliability Coordination Area. Added Southern Minnesota Municipal Power Agency to MISO tariff.</td>
<td>9/20/06</td>
</tr>
<tr>
<td>Version 2</td>
<td>Reflected Ameren’s reconfiguration of their Balancing Areas from three into two.</td>
<td>2/2/07</td>
</tr>
<tr>
<td>Version 3</td>
<td>Reflects the de-certification of the Western Plains East Kansas (WPEK) Balancing Area.</td>
<td>4/1/07</td>
</tr>
<tr>
<td>Version 4</td>
<td>Reflects the conception of the MISO Balancing Authority. To be effective with the start of MISO Balancing Authority operations.</td>
<td>11/14/07</td>
</tr>
<tr>
<td>Version 5</td>
<td>Reflects the addition of Duquesne Light Company (DLCO) local Balancing Authority into the MISO Balancing Authority. To be effective with the start of DLCO into MISO Balancing Authority and MISO Market.</td>
<td>05/07/08</td>
</tr>
<tr>
<td>Version 6</td>
<td>Reflects moving Missouri Public Service -Aquila Networks (MPS) Balancing Authority from MISO to SPP RC. To be effective with the move of MPS to SPP RC.</td>
<td>11/19/08</td>
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<tr>
<td>Version 7</td>
<td>Reflects Duquesne Light Company’s (DLCO) decision to not become a Local Balancing Authority in MISO Balancing Authority Area.</td>
<td>01/31/09</td>
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<tr>
<td></td>
<td>Reflects moving LES, NPPD, and OPPD from MISO RC Area to SPP RC Area. To be effective with the move of LES, NPPD, and OPPD to SPP RC.</td>
<td></td>
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<td></td>
<td>Reflects starting to provide Cleveland Public Power Reliability Coordination services to be effective with the start of the service.</td>
<td></td>
</tr>
<tr>
<td>Version 8</td>
<td>Reflects MidAmerican Energy Company (MEC) and Muscatine Power and Water (MPW) changing from Balancing Authorities (BAs) to Local Balancing Authorities (LBAs) and being incorporated into Midwest ISO Balancing Authority Area. Midwest ISO Reliability Coordination Area boundaries are not changing with this version. This version becomes effective with the incorporation of MEC and MPW LBAs into Midwest ISO BA.</td>
<td>06/23/09</td>
</tr>
<tr>
<td>Version 9</td>
<td>Reflects the addition of Cedar Falls Utilities (CFU) and other miscellaneous updates.</td>
<td>9/23/09</td>
</tr>
<tr>
<td>Version 10</td>
<td>Reflects Dairyland Power Cooperative (DPC) changing from</td>
<td>1/8/10</td>
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<tr>
<td>Version</td>
<td>Description</td>
<td>Effective Date</td>
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<tr>
<td>11</td>
<td>Reflects Big Rivers Electric Corporation (BREC) Balancing Area moving from TVA RC to Midwest ISO RC. Also reflects BREC changing from Balancing Authority (BA) to Local Balancing Authority (LBA) and being incorporated into Midwest ISO BA Area. Note that depending on state regulatory approval, BREC BA integration into Midwest ISO BA may occur subsequent to Midwest ISO becoming BREC’s RC. This version becomes effective with the BREC BA moving into Midwest ISO RC Area.</td>
<td>5/10/10</td>
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<tr>
<td>12</td>
<td>Reflects First Energy LBA exiting the Midwest ISO BA and the Midwest ISO Reliability Footprint, scheduled for June 1, 2011 and Cleveland Public Power exiting its Reliability Coordination Services Agreement with the Midwest ISO, scheduled for June 1, 2011</td>
<td>2/9/11</td>
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<tr>
<td>13</td>
<td>Reflects Missouri River Energy Services becoming a Transmission Owning member of the Midwest ISO and Ohio Valley Electric Corporation and Department of Energy taking Reliability Coordination Services from Midwest ISO scheduled for June 1, 2011.</td>
<td>5/4/11</td>
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<tr>
<td>14</td>
<td>Reflects Lansing Board of Water and Light taking Reliability Coordination Services from MISO. This version becomes effective when LBWL begins RC Services with MISO (currently scheduled for September 1, 2011).</td>
<td>8/1/11</td>
</tr>
<tr>
<td>16</td>
<td>Reflects Entergy taking Reliability Coordination Services from MISO. This version becomes effective when Entergy begins RC services with MISO (currently scheduled for November 19, 2012).</td>
<td>3/2/12</td>
</tr>
<tr>
<td>17</td>
<td>Reflects Entergy (EES) Balancing Area changing from a Balancing Authority (BA) to Local Balancing Authority (LBA) and being incorporated into MISO BA Area (currently scheduled for December 19, 2013). Also included in this revision are multiple Balancing Authorities that are expected to join the MISO RC area on June 1, 2013 and subsequently the MISO BA area on December 19, 2013. The BAs included are City of Conway (CWAY), Brazos Electric Corporation (BRAZ), CLECO, Lafayette Utility System (LAFA), Louisiana Energy and Power Authority (LEPA), Louisiana Generating (LAGN), Plum Point Energy Associates (PLUM), City of Osceola (OMLP), City of West Memphis (WMU), City of</td>
<td>1/1/13</td>
</tr>
<tr>
<td>Version 18</td>
<td>Reflects the Eagan Control Center move from St. Paul, scheduled for December, 2013 and the Midwest ISO name change to Midcontinent ISO, already completed.</td>
<td>11/20/2013</td>
</tr>
<tr>
<td>Version 19</td>
<td>Reflects a clean-up from December 19, 2013 South Region Integration (removing dissolved BAs, removing footnotes, etc.), adding AECC and City of Ames as a Transmission Owners, MIUP as a new LBA, and adding City of Alexandria and Consumers Energy as Reliability Services Customers.</td>
<td>5/8/2014</td>
</tr>
<tr>
<td>Version 20</td>
<td>Reflects the move of the Integrated System (WAPA, Basin Electric, and Heartland Consumers Power District) and Corn Belt Power Cooperative to the SPP Reliability Coordination Footprint scheduled for June 1, 2015. Also reflects additional Transmission Owners in MISO of Rochester Public Utilities, City of Alexandria (LA), City of Marshall (MN), already completed or scheduled in 2015, and the addition of Entergy Mississippi as a Local Balancing Area in the MISO Balancing Authority Area. Added Little Rock, AR as a MISO Control Center scheduled for June, 2015.</td>
<td>3/20/2015</td>
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<tr>
<td>Version 21</td>
<td>Local Balancing Area Entergy Mississippi Abbreviation change from EMI to EMBA, Pioneer Transmission becoming a Transmission Owner, and AEP becoming a MISO TOP</td>
<td>5/8/2018</td>
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<tr>
<td>Version 22</td>
<td>Ohio Valley Electric Corp transferring from the MISO Reliability Footprint to PJM on 12/1/2018 and updating the South Mississippi Electric Power Association to Cooperative Energy. Clean up of directives to operating instructions and SOL/IROL violations to exceedances.</td>
<td>12/1/2018</td>
</tr>
<tr>
<td>Version 23</td>
<td>Henderson Municipal Power &amp; Light entering MISO as an LBA and Transmission Owner and AEP Indiana Michigan Transmission Company, Inc. entering as a Transmission Owner.</td>
<td>3/1/2019</td>
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<tr>
<td>Version 24</td>
<td>GridLiance Heartland BA and LBA transition to MISO RC from TVA RC. GridLiance Heartland LBA transitions into MISO BA.</td>
<td>12/1/2019</td>
</tr>
<tr>
<td>Version 25</td>
<td>Update to Current Day analysis language</td>
<td>9/1/2019</td>
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Introduction

The North American Electric Reliability Corporation (NERC) requires every Region, sub-region, or interregional coordinating group to establish a Reliability Coordinator (RC) to provide the reliability assessment and emergency operations coordination for the Balancing Authorities (BAs) and Transmission Operators (TOPs) within the Regions and across the Regional boundaries.

The Midcontinent Independent System Operator (MISO) serves as the RC for its members, under coordination agreements, and under RC agreements. The MISO RC has certain defined responsibilities and directs the reliable operation of Bulk Power System which is, in general, 100 kV facilities and higher. The MISO RC functions associated with the reliability of the Bulk Power System include review and approval of planned facility transmission line outages\(^1\) & generation outages\(^2\) based upon current and projected system conditions, monitoring of real time loading information and calculating post-contingent loadings on the transmission system, administering loading relief procedures, re-dispatch of generation, and ordering curtailment of transactions and/or load. The MISO RC functions associated with power supply reliability entails monitoring BA performance and ordering the BAs to take actions, including load curtailment and increasing/decreasing generation in situations where an imbalance between generation and load places the system in jeopardy. The MISO reliability procedures and policies are consistent with NERC Standards.\(^3\) MISO operates in multiple NERC Regions and recognizes each Region’s policies and standards. Where there are conflicts in the Regional policies and standards, MISO works with the Regions and members on resolving those conflicts. MISO also provides RC Services for non-market members via Module F.

This document is the Reliability Plan for the MISO RC and is posted at https://www.nerc.com/comm/OC/Pages/ORS/Reliability-Plans.aspx. This version supersedes the previous version.

\(^1\) For those Non-market members within MRO, MISO reviews all planned facility transmission line outages for these entities, notifies the entities of possible conflicts or system conditions that would warrant reconsideration of these planned outages, and works with the entities – along with MISO members - to resolve any issues. Further revisions of NERC Standards may render this distinction obsolete.

\(^2\) MISO discusses and coordinates pending generation maintenance outages to the extent possible, as MISO has authority to deny generation maintenance outages only in cases where such outages would place MISO in an emergency situation.

\(^3\) While the MISO Reliability Coordination Plan describes MISO’s general practices of providing RC services and in some circumstances MISO RC’s endeavor to use best practices beyond what is required by the NERC Reliability Standards, Nothing in this plan shall require MISO RC to go beyond what is required by the NERC Reliability Standards with regard to meeting NERC compliance requirements.
A. Responsibilities – Authorization

1. **Reliable Operations** - MISO has certain defined responsibilities for the reliable operation of the Bulk Power System within its RC Area in accordance with NERC Standards, Regional policies and standards, as well as the governing documents listed in Appendix C of this document. The MISO RC Area is composed of the Transmission Owners’ Areas listed in Appendix A.

1.1 The MISO RC has a Wide Area view of its RC Area and neighboring areas that have an impact on MISO’s Area. The MISO RC and MISO BA have the operating tools, processes and procedures, including the authority, to prevent or mitigate emergency operating situations in both next-day analysis and during real-time conditions per the NERC Standards and Regional standards, as well as the governing documents listed in Appendix C of this document.

The MISO RC operating tools, which provide the Wide Area View, are listed in Section I.

1.2 The MISO RC has clear decision-making authority to act and to direct actions to be taken by its members and non-MISO members within its Reliability Coordination Area to preserve the integrity and reliability of the Bulk Power System.

1.3 The MISO RC and the MISO BA have not delegated any of its RC or BA responsibilities.

2. **Independence** - MISO does and will act first and foremost in the best interest of the reliability for its RC Area and the Eastern Interconnection before that of any other entity. This expectation is clearly identified in the governing documents listed in Appendix C and in the job descriptions of the MISO personnel acting in the role of RC or BA.

3. **MISO RC Operating Instructions Compliance** - Per the governing documents in Appendix C, the BAs, TOPs and other operating entities in the MISO RC Area shall carry out required emergency actions as given in operating instructions by the MISO RC, including the shedding of firm load if required, except in cases involving endangerment to the safety of employees or the public. In those cases, members of the MISO RC Area must immediately inform the MISO RC of the inability to perform the operating instruction.
B. Responsibilities – Delegation of Tasks

1. The MISO RC and the MISO BA have not delegated any RC or BA tasks. Local Balancing Authorities (LBAs) within the MISO Balancing Area are responsible for and will perform tasks per the MISO BA/LBA Coordinated Functional Registration with NERC and the MISO Amended BA Agreement.
C. Common Tasks for Next-Day and Current-Day Operations

This section documents how the MISO conducts current-day and next-day reliability analysis for its Reliability Coordination Area.

1. **Determination of Interconnection Reliability Operating Limits (IROLs)** – The MISO RC determines IROLs based on local, regional and inter-regional studies including seasonal assessments and ad hoc studies. As required, the voltage stability IROLs are calculated in the next day security analysis and limits are conveyed to neighboring RCs and TOPs in the MISO RC Area via the next day security analysis report. The IROL limits are also reviewed each weekday morning during reliability conference calls.

   During the operating day, real time voltage stability analyses are performed to provide updated IROLs, based on the latest system conditions, to the MISO RC. Significant IROL changes are communicated to impacted TOPs in the MISO RC Area and neighboring RCs by email and phone as necessary. Standing IROL interfaces are highlighted in bold in MISO operator displays to differentiate them from System Operating Limit (SOL) flowgates.

   During real time operations, the MISO RC recognizes that a new IROL limit can be created during multiple, normally non-critical outage conditions and the MISO RC determines additional IROLs real-time. To determine these additional IROLs, the MISO RC utilizes a state estimator and real time contingency analysis to analyze real-time and first contingency conditions. These contingency analyses are normally repeated every one to two minutes. In the event a first contingency would cause a post-contingency flow of 125% of the emergency rating, it is automatically assumed the SOL is now an IROL unless there are studies or system knowledge that the SOL is not an IROL. An example of an SOL greater than 125% that would not be considered an IROL is a radial system that would not result in uncontrolled cascading or collapse should the monitored element(s) trip. Contingency analysis results indicating an unsolved contingency which is confirmed to be valid is also considered to be an IROL.

2. **Operation to prevent the likelihood of a SOL or IROL exceedance in another area of the Interconnection and operation when there is a difference in limits** - The MISO RC, through agreements with its RC neighbors, coordinates operations to prevent the likelihood of an SOL or IROL exceedance in another area. These agreements include data exchange, Available Transfer Capability coordination, and Outage Coordination and are listed in Section H.

   TOPs in the MISO RC Area are required to follow operating instructions provided by the MISO RC per NERC Standards and operate to NERC Standards to prevent the likelihood that a disturbance, action, or non-action in its Reliability Coordination Area will result in an SOL or IROL exceedance in another area of the Interconnection.

   When there is a difference in derived limits, MISO RC utilizes the most conservative limit until the difference is resolved.

3. **Operation under known and studied conditions and re-posturing without delay and no longer than 30 minutes** - The MISO RC ensures that entities within its RC Area always operate under known and
studied conditions and that they return their systems to a secure operating state following contingency events within approved timelines, regardless of the number of contingency events that occur or the status of their monitoring, operating and analysis tools. The MISO RC also ensures its BAs and TOPs re-posture the system to within all IROLs following contingencies within T\textsubscript{V} or 30 minutes, whichever is shorter.

On a daily basis, the MISO RC conducts next-day security analysis utilizing planned outages, forecasted loads, generation commitment, and expected net interchange. The analyses include contingency analysis, voltage stability analysis on key interfaces and a review of reactive reserves for defined areas when appropriate. These analyses model peak conditions for the day and are conducted utilizing first contingency (N-1) analysis. Results and mitigation are documented in the Next-Day Security Analysis Report and distributed to MISO Reliability staff. The Next-Day Security Analysis Report is also posted on the MISO Extranet secure website for distribution from this secure website for TOPs and BAs in the MISO Reliability Coordination Area and neighbors to view and download. Mitigation plans are formed as needed for potential exceedances determined in the next day security analysis. Mitigation is of the form of additional unit commitment or may be documented in an operating guide to be utilized by the MISO RC and TOP.

MISO performs Current Day Security Analysis studies as needed throughout the day. Voltage Stability analyses are also performed continuously and on demand as system conditions warrant for each voltage stability flowgate. Results from Voltage stability analysis are available to MISO Reliability staff and also posted to the MISO Extranet for the TOPs and BAs in the MISO Reliability Coordination Area and neighbors.

The MISO Daily Reliability Coordination Report is also posted on the MISO Extranet secure website for TOPs and BAs in the MISO Reliability Coordination Area and neighbors to view and download. The MISO Daily Reliability Coordination Report includes significant generation outages, significant line outages, projected constraints, voltage security assessment results, reactive reserves for defined areas when appropriate, TLR summary from the past 24 hours, and forecasted weather conditions. The MISO Daily Reliability Coordination Report is reviewed each weekday morning with TOPs, the MISO BA, Balancing Areas in the MISO Reliability Coordination Area, and neighboring RCs where expected system conditions for the day are discussed, along with action required to mitigate any abnormal conditions. Additional conference calls are conducted with the same group when conditions warrant.

4. **Communicating SOLs and IROLs to Transmission Service providers within RC Area** – MISO communicates IROLs within its wide-area view and provides updates to IROLs as described above via reports, morning conference calls, and real-time via voice and messaging. Standing IROLs are documented and communicated via operating guides. In general, SOLs are in the form of thermal equipment limits and are provided by Transmission Owners to MISO. If transmission service is sold on the IROL or SOL Flowgate, an adjustment is made to the AFC to account for the reservation.

5. **MISO RC and BA process for issuing operating instructions** - MISO has implemented a communication protocol for the issuing/receiving of operating instructions. The MISO RC and/or MISO BA issues operating instructions in a clear, concise and definitive manner. The MISO RC and/or MISO BA ensures that the person receiving the operating instruction repeats the information back correctly, and acknowledges the response as correct or repeats the original statement again to
resolve any misunderstandings. MISO’s process for issuing operating instructions is documented in the “Communications Protocol For Operating Instructions” procedure.
D. Next-Day Operations

This section documents how the MISO conducts next-day reliability analysis for its Reliability Coordination Area.

1. Reliability Analysis and System Studies - The MISO RC conducts next-day reliability analyses for its Area to ensure that the Bulk Power System can be operated reliably in normal and post contingency conditions.

On a daily basis, the MISO RC conducts next-day security analysis utilizing known outages, forecasted loads, generation commitment and dispatch, and expected net interchange. All facilities 100 kV and above and some non-BES facilities in the MISO RC Area and first tier Balancing Areas are monitored for all contingency cases and the base case. Base case flows on all monitored facilities are compared against the normal rating. Post-contingent flows for all monitored facilities are compared against their emergency rating for all contingencies. Voltage and transient stability analysis is conducted on key critical interfaces to determine a flow limit. Reactive reserves for specific areas are reviewed to ensure they are above necessary levels.

Mitigation plans are formed as needed for potential violations determined in the next day security analysis. Mitigation is of the form of additional unit commitment, restriction on unit output, or may be documented in an operating guide to be utilized by the MISO RC and TOPs.

1.1 Parallel Flows – The MISO RC monitors parallel flows to ensure that its Reliability Coordination Area does not burden another Reliability Coordination Area. To ensure that the impact of parallel flows is considered in the next day security analysis, all first tier BA Areas and key second and third tier BA Areas are modeled in detail and updated in the analysis each day. This includes updating their unit status, transmission outages, load forecast, interchange and generation dispatch.

2. Information Sharing – BAs, Generation Operators and TOPs in the MISO Reliability Coordination Area and neighboring RCs provide to the MISO RC all information required for system studies, such as critical facility status, load, generation, and Operating Reserve projections via the SDX. The entities in the MISO Reliability Coordination Area provide generation and transmission facility statuses to the MISO outage scheduling application per MISO outage scheduling requirements. MISO Reliability Coordination Area load forecast is provided in the SDX. MISO BA load is determined by MISO load forecasting tools. Known interchange transactions are provided as NERC E-Tags. MISO obtains the equivalent information for entities outside the MISO Reliability Coordination Area from the SDX and NERC E-Tags.

3. Sharing of Study Results - When conditions warrant or upon request, the MISO RC shares the results of its system studies with the entities within its Reliability Coordination Area or with other RCs. Study results for the next day typically are available no later than 16:00 Eastern Standard Time, unless circumstances warrant otherwise.

Next-Day Security Analysis Report is distributed to MISO Reliability staff. The Next-Day Security Analysis Report is also posted on the MISO Extranet secure website for distribution to TOPs and
BAs in the MISO Reliability Coordination Area and neighboring RCs to view and download. Any reliability entity that is subject to the NERC Data Confidentiality Agreement may access the Next-Day Security Analysis Report, with approved access, via the MISO Extranet secure web site.

The MISO RC has procedures indicating when it will initiate a conference call or other appropriate communications to address the results of its reliability analyses. The MISO RC hosts a conference call each business day that is normally utilized for this purpose.
E. Current-Day Operations

This section documents how the MISO conducts current-day reliability analysis for its Reliability Coordination Area.

1. The process MISO RC uses to monitor all Bulk Power System facilities, including sub-transmission information as needed, within the MISO Reliability Coordination Area and adjacent areas as necessary to ensure that, at any time, regardless of prior planned or unplanned events, the MISO RC is able to determine any potential SOL and IROL exceedances within its Reliability Coordination Area is as follows:

MISO RC utilizes a state estimator and real-time contingency analysis as its primary tool to monitor facilities. The state estimator model includes all facilities 100 kV and above in the MISO Reliability Coordination Area and extensive representation of 69 kV facilities. The model also has extensive representation of neighboring facilities in order to provide an effective wide-area view. This model is updated quarterly and may be updated on demand when deemed necessary.

Real Time Contingency Analysis (RTCA) is performed on over 10,000 contingencies utilizing the state estimator model normally at least every five minutes. Contingencies include all MISO Reliability Coordination Area equipment 100 kV and above, some non-BES equipment, and neighboring contingencies that would impact MISO Reliability Coordination Area facilities.

MISO utilizes a Real-Time Line Outage Distribution Factor (RTLODF) Tool to monitor selected PTDF and OTDF flowgates to provide a backup to RTCA monitoring. Post-contingent loading on OTDF flowgates is calculated using SCADA data and LODFs automatically updated from a topology processor that does not rely on the state estimator solution.

SCADA alarming is utilized to alert the MISO RC of any actual low or high voltages or facilities loaded beyond their normal or emergency limits.

In addition to the above applications, MISO utilizes a dynamically updated transmission overview display to maintain a wide area view. Transmission facilities 230 kV and above are depicted on the overview with flows (MW and MVAR). This display provides indication of facilities out of service, high and low voltage warning and alarming, and facilities loaded to 90% and 100% of ratings. For more detailed monitoring, dynamically updated Balancing Area wide displays are used to view facilities 100 kV and above, including flows (MW and MVAR), voltages, generator outputs, and facilities out of service. Finally, bus level one-line diagrams are utilized for station level information.

1.1. The MISO RC notifies neighboring RCs of operational concerns (e.g. declining voltages, excessive reactive flows, or an IROL exceedance) that it identifies within the neighboring Reliability Coordination Area via direct phone calls, conference calls, NERC hotline calls, and/or RCIS messages. The MISO RC has documented seams agreements with neighboring RCs that are listed in Section H. MISO RC directs action to provide emergency assistance to all Reliability Coordination neighbors, during declared emergencies, which is required to mitigate the operational concern to the extent that the same entities are taking in kind steps and the assistance would be effective.
2. The MISO RC maintains awareness of the status of all current critical facilities whose failure, degradation or disconnection could result in an SOL or IROL exceedance within its Reliability Coordination Area via State Estimator, RTCA, SCADA alarming, and transmission displays. The MISO RC is aware of the status of any facilities that may be required to assist Reliability Coordination Area restoration objectives via these same displays and tools.

3. The MISO RC is continuously aware of conditions within its Reliability Coordination Area includes this information in its reliability assessments via automatic updates to the state estimator, Flowgate Monitoring Tool, and transmission displays. The MISO RC monitors its MISO Reliability Coordination Area parameters, including the following:

3.1. Current status of Bulk Power System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Special Protection Systems and system loading are monitored by state estimator, RTCA, SCADA Alarming, Flowgate Monitoring Tool, and transmission displays. Balancing Areas are required to report to MISO RC when Automatic Voltage Regulators are not in-service. TOPs are required to report to the MISO RC when Special Protection Systems change status.

3.2. Current pre-CONTINGENCY element conditions (voltage, thermal, or stability) are monitored by state estimator, SCADA Alarming, Flowgate Monitoring Tool, and transmission displays.

3.3. Current post-CONTINGENCY element conditions (voltage, thermal, or stability) are monitored by RTCA, Flowgate Monitoring Tool, and transmission displays.

3.4. System real reserves are monitored versus required per Balancing Area in the Market Monitoring Tool. Reactive reserves versus required are monitored via monitoring adequacy of calculated post-contingent steady state voltages versus voltage limits, voltage stability interfaces against limits, and reactive reserves versus required for defined zones.

3.5. Capacity and energy adequacy conditions via monitoring reserve requirements and regional reporting.

3.6. Current ACE for all Balancing Areas is displayed in a trend graph to MISO RC. When ACE exceeds L_{10}, graph changes colors and alerts operator of magnitude of ACE and duration ACE has exceeded L_{10}.

3.7. Current local procedures, such as operating guides, monitored via discussions with local TOP and statuses of their use are logged in the MISO RC log. TLR procedures in effect are monitored via the NERC Interchange Distribution Calculator.

3.8. Planned generation dispatches for MISO market area are provided to the MISO RC in the form of the unit commitment plan. For the non-market area, generation outages are reported to MISO via the MISO Outage Scheduler application.

3.9. Planned transmission or generation outages are reported to MISO via the MISO Outage Scheduler application.
3.10. Contingency Events are monitored by state estimator, RTCA, SCADA Alarming, Flowgate Monitoring Tool, and transmission displays. TOPs and BAs are required to report Contingency Events to MISO RC.

4. The MISO RC monitors Bulk Power System parameters that may have significant impacts upon its Reliability Coordination Area and neighboring Reliability Coordination areas with respect to:

4.1. The MISO RC maintains awareness of all Interchange Transactions that wheel-through, source, or sink in its Reliability Coordination via NERC E-tags and NERC IDC displays. Interchange Transaction information is made available to all RCs via NERC E-tags.

4.2. The MISO RC, in concert with the Balancing and Interchange Authorities within its Reliability Coordination Area, evaluates and assesses any additional Interchange Transactions that would exceed IROL or SOLs by using the NERC IDC as a look-ahead tool. As flows approach their IROL or SOLs, the MISO RC evaluates the incremental loading next-hour transactions would have on the SOLs or IROLs and determines if action needs to be taken to prevent an SOL or IROL exceedance. The MISO RC has the authority to direct all actions necessary and may utilize all resources to address a potential or actual IROL exceedance up to and including load shedding.

4.3. The MISO RC and MISO BA monitors Balancing Area Operating Reserves versus required to ensure the required amount of Operating Reserves are provided and available as required to meet NERC Control Performance Standards via the Market Monitoring Tool. The MISO RC and the MISO BA are alerted if reserves fall below required. If necessary, the MISO RC will direct the Balancing Area to replenish reserves including obtaining assistance from neighbors as needed.

4.4. The MISO RC identifies the cause of potential or actual SOL or IROL exceedances via analysis of state estimator results, RTCA results, SCADA Alarming of outages, Flowgate Monitoring Tool results, transmission displays of changes, and Interchange Transaction impacts. The MISO RC will initiate control actions including transmission switching, generation redispatch, and/or emergency procedures to relieve the potential or actual IROL exceedance without delay, and no longer than 30 minutes. The MISO RC is authorized to direct utilization of all resources, including load shedding, to address a potential or actual IROL exceedance. The MISO RC will not rely solely on NERC TLR to mitigate an IROL exceedance.

4.5. The MISO RC communicates start and end times for time error corrections to all Balancing Areas within its Reliability Coordination Area via its messaging system. The MISO RC communicates Geo-Magnetic Disturbance forecast information to BAs, TOPs, and Generation Operators via its messaging system. MISO RC will assist in development of any required response plan and will establish an Emergency Operating Guide as needed or move to conservative operating mode to mitigate impacts as needed.
4.6. The MISO RC (Carmel, Eagan, and Little Rock locations) participates in NERC Hotline discussions, assist in the assessment of reliability of the Regions and the overall interconnected system, and coordinate actions in anticipated or actual emergency situations. The MISO RC will disseminate this information via text messaging, individual phone calls, or blast calls within its area as appropriate.

4.7. The MISO RC monitors system frequency via trend graph. The graph visually alerts the MISO RC when frequency falls below 59.95 Hz or is greater than 60.05 Hz. MISO BA monitors its ACE, while the MISO RC monitors each Balancing Area’s ACE via trend graph within the Reliability Coordination Area. Both the MISO BA and the MISO RC receive a visual indication when ACE exceeds L10 and/or BAAL. When necessary, MISO RC directs Balancing Areas with ACEs larger than L10 to return within L10, and directs Balancing Areas to return to within BAAL. The MISO RC will direct BAs to utilize all resources, including firm load shedding, as necessary to relieve an emergency condition.

4.8. The MISO RC coordinates with other RCs and its BAs, Generation Operators, and TOPs, as needed, on the development and implementation of action plans and operating guides to mitigate potential or actual SOL or IROL exceedances, or CPS1, BAAL, or Reportable Balancing Contingency Event criteria. The MISO RC coordinates pending generation and transmission maintenance outages with other RCs and its BAs, Generation Operators, and TOPs, as needed and within code of conduct requirements, real time via telephone and next-day, per the MISO outage scheduling process.

4.9. The MISO RC will assist its BA Areas in arranging for assistance from neighboring RCs or BA Areas via the Energy Emergency Alert (EEA) notification process and will conference parties together as appropriate.

4.10. The MISO RC monitors Balancing Areas’ ACEs to identify the sources of large ACEs that may be contributing to frequency, time error, or inadvertent interchange and directs corrective actions with the appropriate BAs per 4.7 above.

4.11. The TOPs within MISO Reliability Area inform MISO of all changes in status of Special Protection Systems (SPS) including any degradation or potential failure to operate as expected by the TOP. The MISO RC factors these SPS changes into its reliability analyses.

5. The MISO RC issues alerts, as appropriate, to all its Balancing Areas and TOPs via dedicated text messaging, individual phone calls, or blast calls when it foresees a transmission problem (such as an SOL or IROL exceedance, loss of reactive reserves, etc.) within its Reliability Area that requires notification. The MISO RC issues alerts, as appropriate, to all RCs via the Reliability Coordinator Information System when it foresees a transmission problem (such as an SOL or IROL exceedance, loss of reactive reserves, etc.) within its Reliability Area that requires notification.

6. The MISO RC confirms reliability assessment results via analyzing results of state estimator/RTCA, and discussions with local TOPs and neighboring RCs. The MISO RC identifies options to mitigate potential or actual SOL or IROL exceedances by examining existing operating guides, system knowledge, and power flow analysis to identify and implement only those actions as necessary as to always act in the best interests of the interconnection.
F. Emergency Operations

1. The MISO RC utilizes the MISO Emergency Operating Procedures, posted on the www.misoenergy.org site, to return the transmission system to within the IROL as soon as possible, but no longer than 30 minutes. This procedure includes the actions (e.g. reconfiguration, re-dispatch or load shedding) the MISO RC will direct until relief is achieved.

2. The MISO RC utilizes the MISO Emergency Operating Procedures when it deems that an IROL exceedance are imminent. The MISO Emergency Operating Procedures documents the processes and procedures the MISO RC follows when directing its BAs and TOPs to re-dispatch generation, reconfigure transmission, manage Interchange Transactions, or reduce system demand to mitigate the IROL exceedance, to return the system to a reliable state. The MISO RC coordinates its alert and emergency procedures with other RCs via seam coordination agreements listed in Section H.

3. The MISO RC takes or directs action in the event the loading of transmission facilities progresses to or is projected to progress to an SOL or IROL exceedance.

   3.1 The MISO RC directs reconfiguration and/or re-dispatches within its market area as needed to prevent or relieve SOL or IROL exceedances. In the non-market area of MISO Reliability Coordination Area, the MISO RC will direct reconfiguration and re-dispatch to resolve IROL exceedances. The MISO RC will not rely on or wait for NERC TLR to relieve IROL exceedances. The MISO RC may implement NERC TLR if doing so will provide additional relief.

   3.2 The MISO RC utilizes market-to-market re-dispatch for its market area for reciprocally coordinated flowgates per the Congestion Management Process posted on the www.misoenergy.org site and filed with FERC.

   3.3 The MISO RC acknowledges provisions of the NERC TLR and communicates curtailment information as appropriate to impacted Balancing Authorities.

   3.4 The MISO RC will initiate re-configuration, re-dispatch for market areas, and NERC TLR reductions to relieve overloaded facilities as necessary. The MISO RC will not rely on NERC TLR as an emergency action.

4. The MISO RC utilizes the MISO Emergency Operating Procedures to mitigate an energy emergency within its Reliability Coordination Area. The MISO RC will provide assistance to other RCs per its seams agreements listed in Section H.

5. The MISO RC utilizes the MISO Emergency Operating Procedures when it is experiencing a potential or actual Energy Emergency within any BA, Reserve-Sharing Group, or Load-Serving Entity within its Reliability Coordination Area. The MISO Emergency Operating Procedures document the processes and procedures the MISO RC uses to mitigate the emergency condition, including a request for emergency assistance if required.
G. System Restoration

1. Knowledge of members’ Restoration Plans - The MISO RC is aware of each member’s Restoration Plan and has a written copy of each plan. The MISO has the plans and procedures of every member, which are listed in Appendix A.

   During system restoration, MISO RC monitors restoration progress and acts to coordinate any needed assistance.

2. MISO Restoration Plan - The MISO Restoration Plan includes all BAs and TOPs in its Reliability Coordination Areas. MISO RC takes action to restore normal operations once an operating emergency has been mitigated in accordance with its Restoration Plan. This Restoration Plan is drilled at least annually.

3. Dissemination of Information - The MISO RC serves as the primary contact for disseminating information regarding restoration to neighboring RCs and members not immediately involved in restoration.

   The MISO RC approves, communicates and coordinates the re-synchronizing of major system islands or synchronizing points so as not to cause a burden on member or adjacent Reliability Coordination Areas.
H. Adjacent RC Agreements and Data Sharing

1. Coordination Agreements:
   - MISO and PJM have a Joint Operation Agreement
   - MISO and TVA have a RC Coordination and Notification Plan
   - MISO and IESO have a Coordination Agreement.
   - MISO and SPP have a Joint Operating Agreement.
   - MISO and Southeastern RC have a RC Coordination and Notification Plan.
   - MISO and SaskPower have a RC to RC Agreement.

2. Data Sharing - The MISO RC determines the data requirements to support its reliability coordination tasks and requests such data from members or adjacent RCs. The MISO RC provides for data exchange with members and adjacent RCs, TOPs and BAs via a secure network. MISO Reliability Coordination Area members provide data to MISO via ICCP. MISO RC provides data to entities outside MISO via direct links and ISN.
I. Facility

MISO performs the RC function at the MISO Headquarters in Carmel, Indiana along with the MISO offices in Eagan, Minnesota, and Little Rock, Arkansas. The Carmel, Eagan, and Little Rock offices have the necessary voice and data communication links to appropriate entities within their Reliability Coordination Area for the MISO RC to perform their responsibilities. These communication facilities are staffed and available to act in addressing a real-time emergency condition.

1. **Adequate Communication Links** - The MISO RC maintains satellite phones, Voice Over IP phones which run across the dedicated MISO WAN, cell phones, and redundant, diversely routed telecommunications circuits. Additionally, there are also video links between MISO Carmel Control Room and the MISO Eagan and Little Rock Control Rooms.

2. **Multi-directional Capabilities** – The MISO RC has multi-directional communications capabilities with its members, and with neighboring RCs, for both voice and data exchange to meet reliability needs of the Interconnection.

3. **Real-time Monitoring** - The MISO RC has detailed real-time monitoring capability of its Reliability Coordination Area and all first tier companies surrounding the MISO Reliability Coordination Area to ensure that potential or actual System Operating Limit or Interconnection Reliability Operating Limit exceedances are identified.

   3.1 The MISO RC monitors Bulk Power System elements (generators, transmission lines, buses, transformers, breakers, etc.) that could result in SOL or IROL exceedances within its Reliability Coordination Area. The MISO RC monitors both real and reactive power system flows, and operating reserves, and the status of the Bulk Power System elements that are, or could be, critical to SOLs and IROLs and system restoration requirements within its Reliability Coordination Area.

4. **Study and Analysis Tools**

   4.1 The MISO RC has adequate analysis tools, including state estimation, pre- and post-contingency analysis capabilities (thermal, stability, and voltage), and wide-area overview displays. The MISO RC has detailed monitoring capability of the MISO Reliability Area and sufficient monitoring capability of the surrounding Reliability Areas to ensure potential reliability issues are identified. The MISO RC continuously monitors key transmission facilities in its area in conjunction with the Members monitoring of local facilities and issues.

   The MISO RC ensures that SOL and IROL monitoring and derivations continue if the main monitoring system is unavailable. The MISO RC has backup facilities that shall be exercised if the main monitoring system is unavailable.
The systems utilized by the MISO RC are:

- State Estimator and Contingency Analysis
- Market Monitoring Tool
- Status and Analog Alarming
- Overview Displays of MISO Transmission System via Wallboard
- One line diagrams for entire MISO Transmission System
- Transmission Delta Flow Tool
- Flowgate Monitoring Tool
- Generation Monitoring Tool

The MISO RC utilizes these tools, which provide information that is easily understood and interpreted by the MISO RC operating personnel. The alarm management is designed to classify alarms in priority for heightened awareness of critical alarms.

4.2 The MISO RC controls its RC analysis tools, including approvals for planned maintenance. The MISO RC has procedures in place to mitigate the effects of analysis tool outages.
J. **Staffing**

1. **Staff Adequately Trained and NERC Certified** - MISO maintains trained RCs, BAOS, and a Shift Manager on duty at all times, as well shift Reliability Engineers. The MISO RC and MISO BA staff all operating positions that meet following criteria with personnel that are NERC certified for the applicable functions:

   - Positions that have the primary responsibility, either directly or through communications with others, for the real-time operation of the interconnected Bulk Power System.

   - Positions directly responsible for complying with NERC Standards.

   The MISO RC and MISO BA operating personnel each complete a minimum of 40 hours per year of training and drills using realistic simulations of system emergencies, in addition to other training required to maintain qualified operation personnel.

2. **Comprehensive Understanding** - The MISO RC operating personnel have an extensive understanding of the BAs and TOPs within the MISO Reliability Coordination Area, including the operating staff, operating practices and procedures, restoration priorities and objectives, outage plans, equipment capabilities, and operational restrictions.

   The MISO RC operating personnel place particular attention on SOLs and IROLs and inter-tie facility limits. The MISO ensures protocols are in place to allow MISO RC operating personnel to have the best available information at all times.

MISO’s System Operator Training process describes the process by which System Operations personnel are trained to perform their duties, both at entry level and in continuous training status. MISO also uses the Operator Training Manual to establish training and documentation requirements for System Operators in the form of position specific curricula, NERC certification Guidelines, On-the-Job qualification Guides, and Technical Qualification Training Checklists. The Technical Qualification Training Checklists contain competencies for the RC System Operator position and other operation positions. An analysis of each operator position was conducted by Subject Matter Experts (SME), Management, and training representatives to develop the checklists. These checklists provide a way to identify, track status, and document completion of required initial training for any new System Operator.

MISO uses several means to provide initial and continuous training opportunities for System Operators. MISO Operations Technical Training provides the majority of the technical training. MISO Corporate Training provides much of the corporate and non-technical courses such as Standards of Conduct, Fitness for Duty, Ethics and Employee Conducts and Disciplinary Guidelines. Information Technology (IT) Education conducts training on computer-based applications such as Word, Excel, Access Database, etc. Continuing training is designed to keep all operating personnel knowledgeable of current policies, equipment and management expectations. Drills on emergency procedures and simulated exercises are included in the on-going training activities. Training records are maintained.
3. **Standards of Conduct** - MISO RC and MISO BA are independent of the merchant function. RC and BA Operators do not pass information or data to any wholesale merchant function or retail merchant function that is not made available as soon as practicable to all such wholesale merchant functions. MISO RC and MISO BA staff have completed training on MISO’s Standards of Conduct. Refresher training on MISO’s Standards of Conduct is conducted every year. Training records are maintained.
Appendix A

List of Transmission Owners within the MISO Reliability Coordination Area & the documents associated with each:

<table>
<thead>
<tr>
<th>MISO Members</th>
<th>MISO TO Agreement</th>
<th>MISO Tariff</th>
<th>Coordination Agreement</th>
<th>RC Services Agreement</th>
<th>Appendix I</th>
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### Appendix C

**Responsibilities and Authorities**

The following lists the responsibilities/authorities of the MISO and the documents where those responsibilities/authorities are defined.

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<th>Document</th>
<th>Responsibilities / Authorities</th>
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<tr>
<td>MISO Transmission Owner Agreement</td>
<td>• Security and Reliability of the Transmission System</td>
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<td>• Provide outage coordination</td>
</tr>
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<td>• Take emergency action – including shedding load</td>
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<td>MISO Tariff</td>
<td>• Curtailment of transmission service</td>
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<td>Coordination Agreement</td>
<td>• Security and Reliability of the Transmission System</td>
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<td>• Provide outage coordination</td>
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<td>Interconnection Agreements</td>
<td>• Agreement between Transmission Owners and Generation Owners</td>
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<td>Appendix “I”</td>
<td>• Security and Reliability of the Transmission System</td>
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<td>• Outage coordination for independent transmission Companies (ITC, METC)</td>
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<td>RC Agreement</td>
<td>• Provide Reliability Coordination Services</td>
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<td>Agreement Between Midcontinent ISO and Midcontinent ISO BAs to Implement TEMT</td>
<td>• Agreement between Midcontinent ISO and BAs that are signatories to the agreement. The agreement does not apply to non-MISO members.</td>
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<td>• The agreement delineates the responsibilities between Midcontinent ISO and the BAs as is necessary to allow the TEMT, market tariff, to be implemented.</td>
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<td>MISO BA – Local BA Agreements</td>
<td>• The agreement documents the coordination of the actions associated with the defined BA responsibilities</td>
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Midcontinent Independent System Operator

Regional Transmission Organization (RTO)
Reliability Plan

September 1, 2019
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<td>Version 0</td>
<td>Reformatted and updated MISO RTO Reliability Plan to meet the terms of NERC Operating Standards as approved by NERC.</td>
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<td>Version 1</td>
<td>Removed LGEE and DEVI from Reliability Coordination Area. Added Southern Minnesota Municipal Power Agency to MISO tariff.</td>
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<td>Version 2</td>
<td>Reflected Ameren’s reconfiguration of their Balancing Areas from three into two.</td>
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<td>Version 3</td>
<td>Reflects the de-certification of the Western Plains East Kansas (WPEK) Balancing Area</td>
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<td>Version 4</td>
<td>Reflects the conception of the MISO Balancing Authority. To be effective with the start of MISO Balancing Authority operations.</td>
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<td>Version 5</td>
<td>Reflects the addition of Duquesne Light Company (DLCO) local Balancing Authority into the MISO Balancing Authority. To be effective with the start of DLCO into MISO Balancing Authority and MISO Market.</td>
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<td>Reflects moving Missouri Public Service -Aquila Networks (MPS) Balancing Authority from MISO to SPP RC. To be effective with the move of MPS to SPP RC.</td>
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<td>Reflects Duquesne Light Company’s (DLCO) decision to not become a Local Balancing Authority in MISO Balancing Authority Area. Reflects moving LES, NPPD, and OPPD from MISO RC Area to SPP RC Area. To be effective with the move of LES, NPPD, and OPPD to SPP RC. Reflects starting to provide Cleveland Public Power Reliability Coordination services to be effective with the start of the service.</td>
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<td>Reflects MidAmerican Energy Company (MEC) and Muscatine Power and Water (MPW) changing from Balancing Authorities (BAs) to Local Balancing Authorities (LBAs) and being incorporated into Midwest ISO Balancing Authority Area. Midwest ISO Reliability Coordination Area boundaries are not changing with this version. This version becomes effective with the incorporation of MEC and MPW LBAs into Midwest ISO BA.</td>
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<tr>
<td>11</td>
<td>Reflects Big Rivers Electric Corporation (BREC) Balancing Area moving from TVA RC to Midwest ISO RC. Also reflects BREC changing from Balancing Authority (BA) to Local Balancing Authority (LBA) and being incorporated into Midwest ISO BA Area. Note that depending on state regulatory approval, BREC BA integration into Midwest ISO BA may occur subsequent to Midwest ISO becoming BREC’s RC. This version becomes effective with the BREC BA moving into Midwest ISO RC Area.</td>
<td>5/10/10</td>
</tr>
<tr>
<td>12</td>
<td>Reflects First Energy LBA exiting the Midwest ISO BA and the Midwest ISO Reliability Footprint, scheduled for June 1, 2011 and Cleveland Public Power exiting its Reliability Coordination Services Agreement with the Midwest ISO, scheduled for June 1, 2011</td>
<td>2/9/11</td>
</tr>
<tr>
<td>13</td>
<td>Reflects Missouri River Energy Services becoming a Transmission Owning member of the Midwest ISO and Ohio Valley Electric Corporation and Department of Energy taking Reliability Coordination Services from Midwest ISO scheduled for June 1, 2011.</td>
<td>5/4/11</td>
</tr>
<tr>
<td>14</td>
<td>Reflects Lansing Board of Water and Light taking Reliability Coordination Services from MISO. This version becomes effective when LBWL begins RC Services with MISO (currently scheduled for September 1, 2011).</td>
<td>8/11/2011</td>
</tr>
<tr>
<td>16</td>
<td>Reflects Entergy taking Reliability Coordination Services from MISO. This version becomes effective when Entergy begins RC services with MISO (currently scheduled for November 19, 2012).</td>
<td>3/2/12</td>
</tr>
<tr>
<td>17</td>
<td>Reflects Entergy (EES) Balancing Area changing from a Balancing Authority (BA) to Local Balancing Authority (LBA) and being incorporated into MISO BA Area (currently scheduled for December 19, 2013). Also included in this revision are multiple Balancing Authorities that are expected to join the MISO RC area on June 1, 2013 and subsequently the MISO BA area on December 19, 2013. The BAs included are City of Conway (CWAY), Brazos Electric Corporation (BRAZ), CLECO, Lafayette Utility System (LAFA), Louisiana Energy and Power Authority (LEPA), Louisiana Generating (LAGN), Plum Point Energy Associates (PLUM), City of Osceola (OMLP), City of West Memphis (WMU), City of</td>
<td>1/1/13</td>
</tr>
</tbody>
</table>
North Little Rock (NLR), City of Benton (BUBA), Union Power Partners (PUPP), City of Ruston (DERS), South Mississippi Electric (SME), The listing of BAs above is based on BAs defined on 1/1/13. The BAs are also evaluating the BA boundaries and may determine to change their BA boundaries. This version becomes effective with the BAs listed, pending regulatory approvals, Regional Entity/NERC certifications) moving into MISO RC Area and subsequently the MISO BA Area.

<table>
<thead>
<tr>
<th>Version</th>
<th>Description</th>
<th>Date</th>
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</thead>
<tbody>
<tr>
<td>Version 18</td>
<td>Reflects the Eagan Control Center move from St. Paul, scheduled for December, 2013 and the Midwest ISO name change to Midcontinent ISO, already completed.</td>
<td>11/20/2013</td>
</tr>
<tr>
<td>Version 19</td>
<td>Reflects a clean-up from December 19, 2013 South Region Integration (removing dissolved BAs, removing footnotes, etc.), adding AECC and City of Ames as a Transmission Owners, MIUP as a new LBA, and adding City of Alexandria and Consumers Energy as Reliability Services Customers.</td>
<td>5/8/2014</td>
</tr>
<tr>
<td>Version 20</td>
<td>Reflects the move of the Integrated System (WAPA, Basin Electric, and Heartland Consumers Power District) and Corn Belt Power Cooperative to the SPP Reliability Coordination Footprint scheduled for June 1, 2015. Also reflects additional Transmission Owners in MISO of Rochester Public Utilities, City of Alexandria (LA), City of Marshall (MN), already completed or scheduled in 2015, and the addition of Entergy Mississippi as a Local Balancing Area in the MISO Balancing Authority Area. Added Little Rock, AR as a MISO Control Center scheduled for June, 2015.</td>
<td>3/20/2015</td>
</tr>
<tr>
<td>Version 21</td>
<td>Local Balancing Area Entergy Mississippi Abbreviation change from EMI to EMBA, Pioneer Transmission becoming a Transmission Owner, and AEP becoming a MISO TOP</td>
<td>5/8/2018</td>
</tr>
<tr>
<td>Version 22</td>
<td>Ohio Valley Electric Corp transferring from the MISO Reliability Footprint to PJM on 12/1/2018 and updating the South Mississippi Electric Power Association to Cooperative Energy. Clean up of directives to operating instructions and SOL/IROL violations to exceedances.</td>
<td>12/1/2018</td>
</tr>
<tr>
<td>Version 23</td>
<td>Henderson Municipal Power &amp; Light entering MISO as an LBA and Transmission Owner and AEP Indiana Michigan Transmission Company, Inc. entering as a Transmission Owner.</td>
<td>3/1/2019</td>
</tr>
<tr>
<td>Version 24</td>
<td>GridLiance Heartland BA and LBA transition to MISO RC from TVA RC. GridLiance Heartland LBA transitions into MISO BA.</td>
<td>9/12/2019</td>
</tr>
<tr>
<td>Version 25</td>
<td>Update to Current Day analysis language</td>
<td>9/1/2019</td>
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Introduction

The North American Electric Reliability Corporation (NERC) requires every Region, sub-region, or interregional coordinating group to establish a Reliability Coordinator (RC) to provide the reliability assessment and emergency operations coordination for the Balancing Authorities (BAs) and Transmission Operators (TOPs) within the Regions and across the Regional boundaries.

The Midcontinent Independent System Operator (MISO) serves as the RC for its members, under coordination agreements, and under RC agreements. The MISO RC has certain defined responsibilities and directs the reliable operation of Bulk Power System which is, in general, 100 kV facilities and higher. The MISO RC functions associated with the reliability of the Bulk Power System include review and approval of planned facility transmission line outages and generation outages based upon current and projected system conditions, monitoring of real time loading information and calculating post-contingent loadings on the transmission system, administering loading relief procedures, re-dispatch of generation, and ordering curtailment of transactions and/or load. The MISO RC functions associated with power supply reliability entails monitoring BA performance and ordering the BAs to take actions, including load curtailment and increasing/decreasing generation in situations where an imbalance between generation and load places the system in jeopardy. The MISO reliability procedures and policies are consistent with NERC Standards. MISO operates in multiple NERC Regions and recognizes each Region’s policies and standards. Where there are conflicts in the Regional policies and standards, MISO works with the Regions and members on resolving those conflicts. MISO also provides RC Services for non-market members via Module F.

This document is the Reliability Plan for the MISO RC and is posted at https://www.nerc.com/comm/OC/Pages/ORS/Reliability-Plans.aspx. This version supersedes the previous version.

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1 For those Non-market members within MRO, MISO reviews all planned facility transmission line outages for these entities, notifies the entities of possible conflicts or system conditions that would warrant reconsideration of these planned outages, and works with the entities – along with MISO members - to resolve any issues. Further revisions of NERC Standards may render this distinction obsolete.

2 MISO discusses and coordinates pending generation maintenance outages to the extent possible, as MISO has authority to deny generation maintenance outages only in cases where such outages would place MISO in an emergency situation.

3 While the MISO Reliability Coordination Plan describes MISO’s general practices of providing RC services and in some circumstances MISO RC’s endeavor to use best practices beyond what is required by the NERC Reliability Standards, Nothing in this plan shall require MISO RC to go beyond what is required by the NERC Reliability Standards with regard to meeting NERC compliance requirements.
A. Responsibilities – Authorization

1. Reliable Operations - MISO has certain defined responsibilities for the reliable operation of the Bulk Power System within the its RC Area in accordance with NERC Standards, Regional policies and standards, as well as the governing documents listed in Appendix C of this document. The MISO RC Area is composed of the Transmission Owners’ Areas listed in Appendix A.

1.1 The MISO RC has a Wide Area view of its RC Area and neighboring areas that have an impact on MISO’s Area. The MISO RC and MISO BA have the operating tools, processes and procedures, including the authority, to prevent or mitigate emergency operating situations in both next-day analysis and during real-time conditions per the NERC Standards and Regional standards, as well as the governing documents listed in Appendix C of this document.

The MISO RC operating tools, which provide the Wide Area View, are listed in Section I.

1.2 The MISO RC has clear decision-making authority to act and to direct actions to be taken by its members and non-MISO members within its Reliability Coordination Area to preserve the integrity and reliability of the Bulk Power System.

1.3 The MISO RC and the MISO BA have not delegated any of its RC or BA responsibilities.

2. Independence - MISO does and will act first and foremost in the best interest of the reliability for its RC Area and the Eastern Interconnection before that of any other entity. This expectation is clearly identified in the governing documents listed in Appendix C and in the job descriptions of the MISO personnel acting in the role of RC or BA.

3. MISO RC Operating Instructions Compliance - Per the governing documents in Appendix C, the BAs, TOPs and other operating entities in the MISO RC Area shall carry out required emergency actions as given in operating instructions by the MISO RC, including the shedding of firm load if required, except in cases involving endangerment to the safety of employees or the public. In those cases, members of the MISO RC Area must immediately inform the MISO RC of the inability to perform the operating instruction.
B. Responsibilities – Delegation of Tasks

1. The MISO RC and the MISO BA have not delegated any RC or BA tasks. Local Balancing Authorities (LBAs) within the MISO Balancing Area are responsible for and will perform tasks per the MISO BA/LBA Coordinated Functional Registration with NERC and the MISO Amended BA Agreement.
C. Common Tasks for Next-Day and Current-Day Operations

This section documents how the MISO conducts current-day and next-day reliability analysis for its Reliability Coordination Area.

1. **Determination of Interconnection Reliability Operating Limits (IROLs)** – The MISO RC determines IROLs based on local, regional and inter-regional studies including seasonal assessments and ad hoc studies. As required, the voltage stability IROLs are calculated in the next day security analysis and limits are conveyed to neighboring RCs and TOPs in the MISO RC Area via the next day security analysis report. The IROL limits are also reviewed each weekday morning during reliability conference calls.

   During the operating day, real time voltage stability analyses are performed to provide updated IROLs, based on the latest system conditions, to the MISO RC. Significant IROL changes are communicated to impacted TOPs in the MISO RC Area and neighboring RCs by email and phone as necessary. Standing IROL interfaces are highlighted in bold in MISO operator displays to differentiate them from System Operating Limit (SOL) flowgates.

   During real time operations, the MISO RC recognizes that a new IROL limit can be created during multiple, normally non-critical outage conditions and the MISO RC determines additional IROLs real-time. To determine these additional IROLs, the MISO RC utilizes a state estimator and real time contingency analysis to analyze real-time and first contingency conditions. These contingency analyses are normally repeated every one to two minutes. In the event a first contingency would cause a post-contingency flow of 125% of the emergency rating, it is automatically assumed the SOL is now an IROL unless there are studies or system knowledge that the SOL is not an IROL. An example of an SOL greater than 125% that would not be considered an IROL is a radial system that would not result in uncontrolled cascading or collapse should the monitored element(s) trip. Contingency analysis results indicating an unsolved contingency which is confirmed to be valid is also considered to be an IROL.

2. **Operation to prevent the likelihood of a SOL or IROL exceedance in another area of the Interconnection and operation when there is a difference in limits** - The MISO RC, through agreements with its RC neighbors, coordinates operations to prevent the likelihood of an SOL or IROL exceedance in another area. These agreements include data exchange, Available Transfer Capability coordination, and Outage Coordination and are listed in Section H.

   TOPs in the MISO RC Area are required to follow operating instructions provided by the MISO RC per NERC Standards and operate to NERC Standards to prevent the likelihood that a disturbance, action, or non-action in its Reliability Coordination Area will result in an SOL or IROL exceedance in another area of the Interconnection.

   When there is a difference in derived limits, MISO RC utilizes the most conservative limit until the difference is resolved.

3. **Operation under known and studied conditions and re-posturing without delay and no longer than 30 minutes** - The MISO RC ensures that entities within its RC Area always operate under known and
studied conditions and that they return their systems to a secure operating state following contingency events within approved timelines, regardless of the number of contingency events that occur or the status of their monitoring, operating and analysis tools. The MISO RC also ensures its BAs and TOPs re-posture the system to within all IROLs following contingencies within T\(v\) or 30 minutes, whichever is shorter.

On a daily basis, the MISO RC conducts next-day security analysis utilizing planned outages, forecasted loads, generation commitment, and expected net interchange. The analyses include contingency analysis, voltage stability analysis on key interfaces and a review of reactive reserves for defined areas when appropriate. These analyses model peak conditions for the day and are conducted utilizing first contingency (N-1) analysis. Results and mitigation are documented in the Next-Day Security Analysis Report and distributed to MISO Reliability staff. The Next-Day Security Analysis Report is also posted on the MISO Extranet secure website for distribution from this secure website for TOPs and BAs in the MISO Reliability Coordination Area and neighbors to view and download. Mitigation plans are formed as needed for potential exceedances determined in the next day security analysis. Mitigation is of the form of additional unit commitment or may be documented in an operating guide to be utilized by the MISO RC and TOP.

MISO performs Current Day Security Analysis studies in the operating day for morning, peak or near-peak and minimum load periods MISO performs Current Day Security Analysis as needed throughout the day. The Voltage stability analyses are also performed continuously and on demand as system conditions warrant for each voltage stability flowgate. Results from Current Day Voltage stability analysis are documented in the MISO Current Day Security Analysis Report that is distributed to MISO Reliability staff and analysis data is posted to the MISO Extranet for the TOPs and BAs in the MISO Reliability Coordination Area and neighbors.

The MISO Daily Reliability Coordination Report is also posted on the MISO Extranet secure website for TOPs and BAs in the MISO Reliability Coordination Area and neighbors to view and download. The MISO Daily Reliability Coordination Report includes significant generation outages, significant line outages, projected constraints, voltage security assessment results, reactive reserves for defined areas when appropriate, TLR summary from the past 24 hours, and forecasted weather conditions. The MISO Daily Reliability Coordination Report is reviewed each weekday morning with TOPs, the MISO BA, Balancing Areas in the MISO Reliability Coordination Area, and neighboring RCs where expected system conditions for the day are discussed, along with action required to mitigate any abnormal conditions. Additional conference calls are conducted with the same group when conditions warrant.

4. Communicating SOLs and IROLs to Transmission Service providers within RC Area – MISO communicates IROLs within its wide-area view and provides updates to IROLs as described above via reports, morning conference calls, and real-time via voice and messaging. Standing IROLs are documented and communicated via operating guides. In general, SOLs are in the form of thermal equipment limits and are provided by Transmission Owners to MISO. If transmission service is sold on the IROL or SOL Flowgate, an adjustment is made to the AFC to account for the reservation.

5. MISO RC and BA process for issuing operating instructions - MISO has implemented a communication protocol for the issuing/receiving of operating instructions. The MISO RC and/or
MISO BA issues operating instructions in a clear, concise and definitive manner. The MISO RC and/or MISO BA ensures that the person receiving the operating instruction repeats the information back correctly, and acknowledges the response as correct or repeats the original statement again to resolve any misunderstandings. MISO’s process for issuing operating instructions is documented in the “Communications Protocol For Operating Instructions” procedure.


D. Next-Day Operations

This section documents how the MISO conducts next-day reliability analysis for its Reliability Coordination Area.

1. **Reliability Analysis and System Studies** - The MISO RC conducts next-day reliability analyses for its Area to ensure that the Bulk Power System can be operated reliably in normal and post contingency conditions.

On a daily basis, the MISO RC conducts next-day security analysis utilizing known outages, forecasted loads, generation commitment and dispatch, and expected net interchange. All facilities 100 kV and above and some non-BES facilities in the MISO RC Area and first tier Balancing Areas are monitored for all contingency cases and the base case. Base case flows on all monitored facilities are compared against the normal rating. Post-contingent flows for all monitored facilities are compared against their emergency rating for all contingencies. Voltage and transient stability analysis is conducted on key critical interfaces to determine a flow limit. Reactive reserves for specific areas are reviewed to ensure they are above necessary levels.

Mitigation plans are formed as needed for potential violations determined in the next day security analysis. Mitigation is of the form of additional unit commitment, restriction on unit output, or may be documented in an operating guide to be utilized by the MISO RC and TOPs.

1.1 **Parallel Flows** – The MISO RC monitors parallel flows to ensure that its Reliability Coordination Area does not burden another Reliability Coordination Area. To ensure that the impact of parallel flows is considered in the next day security analysis, all first tier BA Areas and key second and third tier BA Areas are modeled in detail and updated in the analysis each day. This includes updating their unit status, transmission outages, load forecast, interchange and generation dispatch.

2. **Information Sharing** – BAs, Generation Operators and TOPs in the MISO Reliability Coordination Area and neighboring RCs provide to the MISO RC all information required for system studies, such as critical facility status, load, generation, and Operating Reserve projections via the SDX. The entities in the MISO Reliability Coordination Area provide generation and transmission facility statuses to the MISO outage scheduling application per MISO outage scheduling requirements. MISO Reliability Coordination Area load forecast is provided in the SDX. MISO BA load is determined by MISO load forecasting tools. Known interchange transactions are provided as NERC E-Tags. MISO obtains the equivalent information for entities outside the MISO Reliability Coordination Area from the SDX and NERC E-Tags.

3. **Sharing of Study Results** - When conditions warrant or upon request, the MISO RC shares the results of its system studies with the entities within its Reliability Coordination Area or with other RCs. Study results for the next day typically are available no later than 16:00 Eastern Standard Time, unless circumstances warrant otherwise.

Next-Day Security Analysis Report is distributed to MISO Reliability staff. The Next-Day Security Analysis Report is also posted on the MISO Extranet secure website for distribution to TOPs and
BAs in the MISO Reliability Coordination Area and neighboring RCs to view and download. Any reliability entity that is subject to the NERC Data Confidentiality Agreement may access the Next-Day Security Analysis Report, with approved access, via the MISO Extranet secure web site.

The MISO RC has procedures indicating when it will initiate a conference call or other appropriate communications to address the results of its reliability analyses. The MISO RC hosts a conference call each business day that is normally utilized for this purpose.
E. Current-Day Operations

This section documents how the MISO conducts current-day reliability analysis for its Reliability Coordination Area.

1. The process MISO RC uses to monitor all Bulk Power System facilities, including sub-transmission information as needed, within the MISO Reliability Coordination Area and adjacent areas as necessary to ensure that, at any time, regardless of prior planned or unplanned events, the MISO RC is able to determine any potential SOL and IROL exceedances within its Reliability Coordination Area is as follows:

MISO RC utilizes a state estimator and real-time contingency analysis as its primary tool to monitor facilities. The state estimator model includes all facilities 100 kV and above in the MISO Reliability Coordination Area and extensive representation of 69 kV facilities. The model also has extensive representation of neighboring facilities in order to provide an effective wide-area view. This model is updated quarterly and may be updated on demand when deemed necessary.

Real Time Contingency Analysis (RTCA) is performed on over 10,000 contingencies utilizing the state estimator model normally at least every five minutes. Contingencies include all MISO Reliability Coordination Area equipment 100 kV and above, some non-BES equipment, and neighboring contingencies that would impact MISO Reliability Coordination Area facilities.

MISO utilizes a Real-Time Line Outage Distribution Factor (RTLODF) Tool to monitor selected PTDF and OTDF flowgates to provide a backup to RTCA monitoring. Post-contingent loading on OTDF flowgates is calculated using SCADA data and LODFs automatically updated from a topology processor that does not rely on the state estimator solution.

SCADA alarming is utilized to alert the MISO RC of any actual low or high voltages or facilities loaded beyond their normal or emergency limits.

In addition to the above applications, MISO utilizes a dynamically updated transmission overview display to maintain a wide area view. Transmission facilities 230 kV and above are depicted on the overview with flows (MW and MVAR). This display provides indication of facilities out of service, high and low voltage warning and alarming, and facilities loaded to 90% and 100% of ratings. For more detailed monitoring, dynamically updated Balancing Area wide displays are used to view facilities 100 kV and above, including flows (MW and MVAR), voltages, generator outputs, and facilities out of service. Finally, bus level one-line diagrams are utilized for station level information.

1.1. The MISO RC notifies neighboring RCs of operational concerns (e.g. declining voltages, excessive reactive flows, or an IROL exceedance) that it identifies within the neighboring Reliability Coordination Area via direct phone calls, conference calls, NERC hotline calls, and/or RCIS messages. The MISO RC has documented seams agreements with neighboring RCs that are listed in Section H. MISO RC directs action to provide emergency assistance to all Reliability Coordination neighbors, during declared emergencies, which is required to mitigate the operational concern to the extent that the same entities are taking in kind steps and the assistance would be effective.
2. The MISO RC maintains awareness of the status of all current critical facilities whose failure, degradation or disconnection could result in an SOL or IROL exceedance within its Reliability Coordination Area via State Estimator, RTCA, SCADA alarming, and transmission displays. The MISO RC is aware of the status of any facilities that may be required to assist Reliability Coordination Area restoration objectives via these same displays and tools.

3. The MISO RC is continuously aware of conditions within its Reliability Coordination Area includes this information in its reliability assessments via automatic updates to the state estimator, Flowgate Monitoring Tool, and transmission displays. The MISO RC monitors its MISO Reliability Coordination Area parameters, including the following:

3.1. Current status of Bulk Power System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Special Protection Systems and system loading are monitored by state estimator, RTCA, SCADA Alarming, Flowgate Monitoring Tool, and transmission displays. Balancing Areas are required to report to MISO RC when Automatic Voltage Regulators are not in-service. TOPs are required to report to the MISO RC when Special Protection Systems change status.

3.2. Current pre-CONTINGENCY element conditions (voltage, thermal, or stability) are monitored by state estimator, SCADA Alarming, Flowgate Monitoring Tool, and transmission displays.

3.3. Current post-CONTINGENCY element conditions (voltage, thermal, or stability) are monitored by RTCA, Flowgate Monitoring Tool, and transmission displays.

3.4. System real reserves are monitored versus required per Balancing Area in the Market Monitoring Tool. Reactive reserves versus required are monitored via monitoring adequacy of calculated post-contingent steady state voltages versus voltage limits, voltage stability interfaces against limits, and reactive reserves versus required for defined zones.

3.5. Capacity and energy adequacy conditions via monitoring reserve requirements and regional reporting.

3.6. Current ACE for all Balancing Areas is displayed in a trend graph to MISO RC. When ACE exceeds $L_{10}$, graph changes colors and alerts operator of magnitude of ACE and duration ACE has exceeded $L_{10}$.

3.7. Current local procedures, such as operating guides, monitored via discussions with local TOP and statuses of their use are logged in the MISO RC log. TLR procedures in effect are monitored via the NERC Interchange Distribution Calculator.

3.8. Planned generation dispatches for MISO market area are provided to the MISO RC in the form of the unit commitment plan. For the non-market area, generation outages are reported to MISO via the MISO Outage Scheduler application.

3.9. Planned transmission or generation outages are reported to MISO via the MISO Outage Scheduler application.
3.10. Contingency Events are monitored by state estimator, RTCA, SCADA Alarming, Flowgate Monitoring Tool, and transmission displays. TOPs and BAs are required to report Contingency Events to MISO RC.

4. The MISO RC monitors Bulk Power System parameters that may have significant impacts upon its Reliability Coordination Area and neighboring Reliability Coordination areas with respect to:

4.1. The MISO RC maintains awareness of all Interchange Transactions that wheel-through, source, or sink in its Reliability Coordination via NERC E-tags and NERC IDC displays. Interchange Transaction information is made available to all RCs via NERC E-tags.

4.2. The MISO RC, in concert with the Balancing and Interchange Authorities within its Reliability Coordination Area, evaluates and assesses any additional Interchange Transactions that would exceed IROL or SOLs by using the NERC IDC as a look-ahead tool. As flows approach their IROL or SOLs, the MISO RC evaluates the incremental loading next-hour transactions would have on the SOLs or IROLs and determines if action needs to be taken to prevent an SOL or IROL exceedance. The MISO RC has the authority to direct all actions necessary and may utilize all resources to address a potential or actual IROL exceedance up to and including load shedding.

4.3. The MISO RC and MISO BA monitors Balancing Area Operating Reserves versus required to ensure the required amount of Operating Reserves are provided and available as required to meet NERC Control Performance Standards via the Market Monitoring Tool. The MISO RC and the MISO BA are alerted if reserves fall below required. If necessary, the MISO RC will direct the Balancing Area to replenish reserves including obtaining assistance from neighbors as needed.

4.4. The MISO RC identifies the cause of potential or actual SOL or IROL exceedances via analysis of state estimator results, RTCA results, SCADA Alarming of outages, Flowgate Monitoring Tool results, transmission displays of changes, and Interchange Transaction impacts. The MISO RC will initiate control actions including transmission switching, generation redispatch, and/or emergency procedures to relieve the potential or actual IROL exceedance without delay, and no longer than 30 minutes. The MISO RC is authorized to direct utilization of all resources, including load shedding, to address a potential or actual IROL exceedance. The MISO RC will not rely solely on NERC TLR to mitigate an IROL exceedance.

4.5. The MISO RC communicates start and end times for time error corrections to all Balancing Areas within its Reliability Coordination Area via its messaging system. The MISO RC communicates Geo-Magnetic Disturbance forecast information to BAs, TOPs, and Generation Operators via its messaging system. MISO RC will assist in development of any required response plan and will establish an Emergency Operating Guide as needed or move to conservative operating mode to mitigate impacts as needed.
4.6. The MISO RC (Carmel, Eagan, and Little Rock locations) participates in NERC Hotline discussions, assist in the assessment of reliability of the Regions and the overall interconnected system, and coordinate actions in anticipated or actual emergency situations. The MISO RC will disseminate this information via text messaging, individual phone calls, or blast calls within its area as appropriate.

4.7. The MISO RC monitors system frequency via trend graph. The graph visually alerts the MISO RC when frequency falls below 59.95 Hz or is greater than 60.05 Hz. MISO BA monitors its ACE, while the MISO RC monitors each Balancing Area’s ACE via trend graph within the Reliability Coordination Area. Both the MISO BA and the MISO RC receive a visual indication when ACE exceeds L\text{10} and/or BAAL. When necessary, MISO RC directs Balancing Areas with ACEs larger than L\text{10} to return within L\text{10}, and directs Balancing Areas to return to within BAAL. The MISO RC will direct BAs to utilize all resources, including firm load shedding, as necessary to relieve an emergency condition.

4.8. The MISO RC coordinates with other RCs and its BAs, Generation Operators, and TOPs, as needed, on the development and implementation of action plans and operating guides to mitigate potential or actual SOL or IROL exceedances, or CPS1, BAAL, or Reportable Balancing Contingency Event criteria. The MISO RC coordinates pending generation and transmission maintenance outages with other RCs and its BAs, Generation Operators, and TOPs, as needed and within code of conduct requirements, real time via telephone and next-day, per the MISO outage scheduling process.

4.9. The MISO RC will assist its BA Areas in arranging for assistance from neighboring RCs or BA Areas via the Energy Emergency Alert (EEA) notification process and will conference parties together as appropriate.

4.10. The MISO RC monitors Balancing Areas’ ACEs to identify the sources of large ACEs that may be contributing to frequency, time error, or inadvertent interchange and directs corrective actions with the appropriate BAs per 4.7 above.

4.11. The TOPs within MISO Reliability Area inform MISO of all changes in status of Special Protection Systems (SPS) including any degradation or potential failure to operate as expected by the TOP. The MISO RC factors these SPS changes into its reliability analyses.

5. The MISO RC issues alerts, as appropriate, to all its Balancing Areas and TOPs via dedicated text messaging, individual phone calls, or blast calls when it foresees a transmission problem (such as an SOL or IROL exceedance, loss of reactive reserves, etc.) within its Reliability Area that requires notification. The MISO RC issues alerts, as appropriate, to all RCs via the Reliability Coordinator Information System when it foresees a transmission problem (such as an SOL or IROL exceedance, loss of reactive reserves, etc.) within its Reliability Area that requires notification.

6. The MISO RC confirms reliability assessment results via analyzing results of state estimator/RTCA, and discussions with local TOPs and neighboring RCs. The MISO RC identifies options to mitigate potential or actual SOL or IROL exceedances via examining existing operating guides, system knowledge, and power flow analysis to identify and implement only those actions as necessary as to always act in the best interests of the interconnection.
F. Emergency Operations

1. The MISO RC utilizes the MISO Emergency Operating Procedures, posted on the www.misoenergy.org site, to return the transmission system to within the IROL as soon as possible, but no longer than 30 minutes. This procedure includes the actions (e.g. reconfiguration, re-dispatch or load shedding) the MISO RC will direct until relief is achieved.

2. The MISO RC utilizes the MISO Emergency Operating Procedures when it deems that an IROL exceedance are imminent. The MISO Emergency Operating Procedures documents the processes and procedures the MISO RC follows when directing its BAs and TOPs to re-dispatch generation, reconfigure transmission, manage Interchange Transactions, or reduce system demand to mitigate the IROL exceedance, to return the system to a reliable state. The MISO RC coordinates its alert and emergency procedures with other RCs via seam coordination agreements listed in Section H.

3. The MISO RC takes or directs action in the event the loading of transmission facilities progresses to or is projected to progress to an SOL or IROL exceedance.

   3.1 The MISO RC directs reconfiguration and/or re-dispatches within its market area as needed to prevent or relieve SOL or IROL exceedances. In the non-market area of MISO Reliability Coordination Area, the MISO RC will direct reconfiguration and re-dispatch to resolve IROL exceedances. The MISO RC will not rely on or wait for NERC TLR to relieve IROL exceedances. The MISO RC may implement NERC TLR if doing so will provide additional relief.

   3.2 The MISO RC utilizes market-to-market re-dispatch for its market area for reciprocally coordinated flowgates per the Congestion Management Process posted on the www.misoenergy.org site and filed with FERC.

   3.3 The MISO RC acknowledges provisions of the NERC TLR and communicates curtailment information as appropriate to impacted Balancing Authorities.

   3.4 The MISO RC will initiate re-configuration, re-dispatch for market areas, and NERC TLR reductions to relieve overloaded facilities as necessary. The MISO RC will not rely on NERC TLR as an emergency action.

4. The MISO RC utilizes the MISO Emergency Operating Procedures to mitigate an energy emergency within its Reliability Coordination Area. The MISO RC will provide assistance to other RCs per its seams agreements listed in Section H.

5. The MISO RC utilizes the MISO Emergency Operating Procedures when it is experiencing a potential or actual Energy Emergency within any BA, Reserve-Sharing Group, or Load-Serving Entity within its Reliability Coordination Area. The MISO Emergency Operating Procedures document the processes and procedures the MISO RC uses to mitigate the emergency condition, including a request for emergency assistance if required.
G. System Restoration

1. Knowledge of members’ Restoration Plans - The MISO RC is aware of each member’s Restoration Plan and has a written copy of each plan. The MISO has the plans and procedures of every member, which are listed in Appendix A.

   During system restoration, MISO RC monitors restoration progress and acts to coordinate any needed assistance.

2. MISO Restoration Plan - The MISO Restoration Plan includes all BAs and TOPs in its Reliability Coordination Areas. MISO RC takes action to restore normal operations once an operating emergency has been mitigated in accordance with its Restoration Plan. This Restoration Plan is drilled at least annually.

3. Dissemination of Information - The MISO RC serves as the primary contact for disseminating information regarding restoration to neighboring RCs and members not immediately involved in restoration.

   The MISO RC approves, communicates and coordinates the re-synchronizing of major system islands or synchronizing points so as not to cause a burden on member or adjacent Reliability Coordination Areas.
H. Adjacent RC Agreements and Data Sharing

1. Coordination Agreements:

- MISO and PJM have a Joint Operation Agreement
- MISO and TVA have a RC Coordination and Notification Plan
- MISO and IESO have a Coordination Agreement.
- MISO and SPP have a Joint Operating Agreement.
- MISO and Southeastern RC have a RC Coordination and Notification Plan.
- MISO and SaskPower have a RC to RC Agreement.

2. Data Sharing - The MISO RC determines the data requirements to support its reliability coordination tasks and requests such data from members or adjacent RCs. The MISO RC provides for data exchange with members and adjacent RCs, TOPs and BAs via a secure network. MISO Reliability Coordination Area members provide data to MISO via ICCP. MISO RC provides data to entities outside MISO via direct links and ISN.
I. Facility

MISO performs the RC function at the MISO Headquarters in Carmel, Indiana along with the MISO offices in Eagan, Minnesota, and Little Rock, Arkansas. The Carmel, Eagan, and Little Rock offices have the necessary voice and data communication links to appropriate entities within their Reliability Coordination Area for the MISO RC to perform their responsibilities. These communication facilities are staffed and available to act in addressing a real-time emergency condition.

1. Adequate Communication Links - The MISO RC maintains satellite phones, Voice Over IP phones which run across the dedicated MISO WAN, cell phones, and redundant, diversely routed telecommunications circuits. Additionally, there are also video links between MISO Carmel Control Room and the MISO Eagan and Little Rock Control Rooms.

2. Multi-directional Capabilities – The MISO RC has multi-directional communications capabilities with its members, and with neighboring RCs, for both voice and data exchange to meet reliability needs of the Interconnection.

3. Real-time Monitoring - The MISO RC has detailed real-time monitoring capability of its Reliability Coordination Area and all first tier companies surrounding the MISO Reliability Coordination Area to ensure that potential or actual System Operating Limit or Interconnection Reliability Operating Limit exceedances are identified.

3.1 The MISO RC monitors Bulk Power System elements (generators, transmission lines, buses, transformers, breakers, etc.) that could result in SOL or IROL exceedances within its Reliability Coordination Area. The MISO RC monitors both real and reactive power system flows, and operating reserves, and the status of the Bulk Power System elements that are, or could be, critical to SOLs and IROLs and system restoration requirements within its Reliability Coordination Area.

4. Study and Analysis Tools

4.1 The MISO RC has adequate analysis tools, including state estimation, pre-and post-contingency analysis capabilities (thermal, stability, and voltage), and wide-area overview displays. The MISO RC has detailed monitoring capability of the MISO Reliability Area and sufficient monitoring capability of the surrounding Reliability Areas to ensure potential reliability issues are identified. The MISO RC continuously monitors key transmission facilities in its area in conjunction with the Members monitoring of local facilities and issues.

The MISO RC ensures that SOL and IROL monitoring and derivations continue if the main monitoring system is unavailable. The MISO RC has backup facilities that shall be exercised if the main monitoring system is unavailable.
The systems utilized by the MISO RC are:

- State Estimator and Contingency Analysis
- Market Monitoring Tool
- Status and Analog Alarming
- Overview Displays of MISO Transmission System via Wallboard
- One line diagrams for entire MISO Transmission System
- Transmission Delta Flow Tool
- Flowgate Monitoring Tool
- Generation Monitoring Tool

The MISO RC utilizes these tools, which provide information that is easily understood and interpreted by the MISO RC operating personnel. The alarm management is designed to classify alarms in priority for heightened awareness of critical alarms.

4.2 The MISO RC controls its RC analysis tools, including approvals for planned maintenance. The MISO RC has procedures in place to mitigate the effects of analysis tool outages.
J. Staffing

1. Staff Adequately Trained and NERC Certified - MISO maintains trained RCs, BAOs, and a Shift Manager on duty at all times, as well shift Reliability Engineers. The MISO RC and MISO BA staff all operating positions that meet following criteria with personnel that are NERC certified for the applicable functions:

- Positions that have the primary responsibility, either directly or through communications with others, for the real-time operation of the interconnected Bulk Power System.
- Positions directly responsible for complying with NERC Standards.

The MISO RC and MISO BA operating personnel each complete a minimum of 40 hours per year of training and drills using realistic simulations of system emergencies, in addition to other training required to maintain qualified operation personnel.

2. Comprehensive Understanding - The MISO RC operating personnel have an extensive understanding of the BAs and TOPs within the MISO Reliability Coordination Area, including the operating staff, operating practices and procedures, restoration priorities and objectives, outage plans, equipment capabilities, and operational restrictions.

The MISO RC operating personnel place particular attention on SOLs and IROLs and inter-tie facility limits. The MISO ensures protocols are in place to allow MISO RC operating personnel to have the best available information at all times.

MISO’s System Operator Training process describes the process by which System Operations personnel are trained to perform their duties, both at entry level and in continuous training status. MISO also uses the Operator Training Manual to establish training and documentation requirements for System Operators in the form of position specific curricula, NERC certification Guidelines, On-the-Job qualification Guides, and Technical Qualification Training Checklists. The Technical Qualification Training Checklists contain competencies for the RC System Operator position and other operation positions. An analysis of each operator position was conducted by Subject Matter Experts (SME), Management, and training representatives to develop the checklists. These checklists provide a way to identify, track status, and document completion of required initial training for any new System Operator.

MISO uses several means to provide initial and continuous training opportunities for System Operators. MISO Operations Technical Training provides the majority of the technical training. MISO Corporate Training provides much of the corporate and non-technical courses such as Standards of Conduct, Fitness for Duty, Ethics and Employee Conducts and Disciplinary Guidelines. Information Technology (IT) Education conducts training on computer-based applications such as Word, Excel, Access Database, etc. Continuing training is designed to keep all operating personnel knowledgeable of current policies, equipment and management expectations. Drills on emergency procedures and simulated exercises are included in the on-going training activities. Training records are maintained.
3. **Standards of Conduct** - MISO RC and MISO BA are independent of the merchant function. RC and BA Operators do not pass information or data to any wholesale merchant function or retail merchant function that is not made available as soon as practicable to all such wholesale merchant functions. MISO RC and MISO BA staff have completed training on MISO’s Standards of Conduct. Refresher training on MISO’s Standards of Conduct is conducted every year. Training records are maintained.
Appendix A

List of Transmission Owners within the MISO Reliability Coordination Area & the documents associated with each:

<table>
<thead>
<tr>
<th>MISO Members</th>
<th>MISO TO Agreement</th>
<th>MISO Tariff</th>
<th>Coordination Agreement</th>
<th>RC Services Agreement</th>
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<td>SME</td>
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Appendix C
Responsibilities and Authorities
The following lists the responsibilities/authorities of the MISO and the documents where those responsibilities/authorities are defined.

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<thead>
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<th>Document</th>
<th>Responsibilities / Authorities</th>
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</thead>
</table>
| MISO Transmission Owner Agreement | • Security and Reliability of the Transmission System  
   • Provide outage coordination  
   • Take emergency action – including shedding load |
| MISO Tariff | • Curtailment of transmission service |
| Coordination Agreement | • Security and Reliability of the Transmission System  
   • Provide outage coordination |
| Interconnection Agreements | • Agreement between Transmission Owners and Generation Owners |
| Appendix “I” | • Security and Reliability of the Transmission System  
   • Outage coordination for independent transmission Companies (ITC, METC) |
| RC Agreement | • Provide Reliability Coordination Services |
| Agreement Between Midcontinent ISO and Midcontinent ISO BAs to Implement TEMT | • Agreement between Midcontinent ISO and BAs that are signatories to the agreement. The agreement does not apply to non-MISO members.  
   • The agreement delineates the responsibilities between Midcontinent ISO and the BAs as is necessary to allow the TEMT, market tariff, to be implemented. |
| MISO BA – Local BA Agreements | • The agreement documents the coordination of the actions associated with the defined BA responsibilities |
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**Introduction**

The North American Electric Reliability Corporation (NERC) Standards and the Mandatory Reliability Standards (MRS) adopted by the British Columbia Utilities Commission (BCUC) require every Regional Reliability Organization (RRO), subregion, or interregional coordinating group to establish a Reliability Coordinator to continually assess transmission reliability and coordinate emergency operations among the operating entities within the region and across the regional boundaries.

BC Hydro and Power Authority serves as both the Reliability Coordinator and the Balancing Authority for the Province of British Columbia, within the Western Electricity Coordinating Council. The Reliability Coordinator functions are under the functional authority of the Manager, Provincial Reliability Coordination Operations, who reports to the Director of Transmission and Distribution System Operations. The department performing the Reliability Coordinator functions is referred to as the British Columbia Reliability Coordinator or BCRC. The BCRC reliability area is defined as the physical footprint of the province of British Columbia. The BCRC is recognized as the RC for the BC Hydro Balancing Authority and for the following Transmission Operators: BC Hydro, FortisBC and Teck Metals Ltd.

British Columbia is synchronously interconnected to the Province of Alberta and to the State of Washington. BC Hydro has established a Reliability Coordinator Standards of Conduct ensuring functional separation and independence, and aligning the transmission activities, planning, and operations to BCUC, NERC and FERC standards. All power marketing activities are carried out by BC Hydro’s wholly owned subsidiary, Powerex Corp. which exists in a separate headquarters than the BC Hydro Control Centres.

The BCRC is responsible for the bulk electric system (BES) reliability within its Reliability Coordination Area. BES reliability functions include assessment of real-time, current day and
next-day operating conditions, loading relief procedures, re-dispatch of generation, coordination of transmission and generation outages and ordering curtailment of transactions and/or load or other actions as deemed necessary to maintain or restore BES reliability. BCRC policies and procedures are consistent with those of the B.C. MRS.

The BCRC authorized personnel have the authority to approve or cancel planned transmission and generation outages within its RC area (including those to its telecommunication system, monitoring and analysis capabilities).
### A. Responsibilities – Authorization

**Reliable Operations** – The British Columbia Utilities Commission, through Order G-199-19, has granted the BCRC with the authority to act as necessary to support and maintain the Reliable Operation of the Bulk Electric System of B.C. and the Western Interconnection. Through the authority granted by Order G-199-19, the BC Reliability Coordinator (BCRC) has the responsibility and authority to act to address the reliability of the RC area, in both real-time and next-day operations, by issuing Operating Instructions to the B.C. MRS Registered Entities to take actions up to and including shedding firm load. The BCRC authorized personnel have the responsibility and authority to direct these actions without obtaining prior approval from higher level personnel within BC Hydro.

The BCRC has a wide-area view, operating tools, processes and procedures and the authority given by Order G-199-19 to prevent or mitigate emergency operating situations in real-time, current-day operations, and next-day operations. More detail is provided in appropriate sections of this document.

The BCRC has clear decision-making authority to act and to direct actions to be taken by B.C MRS Registered Entities within its Reliability Coordination Area to preserve the integrity and reliability of the Bulk Electric System. The BCRC responsibilities and authorities are clearly defined in the governing documents.

The BCRC has not delegated any of its Reliability Coordinator responsibilities.

**Independence** – The BCRC, as the Reliability Coordinator for the Province of B.C., does and will act first and foremost in the best interest of its Reliability Coordination Area and the Western Interconnection before that of any other entity. The expectation of independence is clearly identified in the governing documents included in Appendix A.

**BCRC Operating Instruction Compliance** – As indicated in BCUC Order G-199-19, the B.C. MRS Registered Entities in the BCRC area are obligated to comply with the BCRC Operating Instructions, unless such actions cannot be physically implemented or will violate safety, equipment, regulatory, or statutory requirements. Under these circumstances, the entity shall, without delay, inform the BCRC authorized personnel of the inability to perform the instruction, so that the BCRC authorized personnel may implement alternate actions.
B. Responsibilities – Delegation of Tasks

The BCRC has not delegated any of its Reliability Coordinator responsibilities.
C. Common Tasks for Next-Day and Current-Day Operations

This section documents how the BCRC conducts current-day and next-day reliability analysis for its Reliability Coordination Area.

1. **Determination of Interconnection Reliability Operating Limits (IROLs)** – The BCRC has a System Operating Limits Methodology for the operation horizon which includes establishing and communicating IROLs. The RC will determine the need for establishing IROLs based on studies performed one or more days prior to real-time that identify instability, Cascading or uncontrolled separation affecting an undetermined area or a wide area of the system. Presently, there are no IROLs identified in the BCRC Area.

   When establishing IROLs, the BCRC will coordinate with impacted entities to develop an Operating plan that identifies facilities that are critical to the derivation of the IROL, the value of the IROL and its associated Tv, the associated contingencies, and to ensure that all entities understand their role in the plan.

2. **Operation to prevent the likelihood of a SOL or IROL exceedance in another area of the Interconnection and operation when there is a difference in limits** - The BCRC, through agreements with its RC neighbours, coordinates operations to prevent the likelihood of an SOL or IROL exceedance in another area. These agreements include data exchange to support the reliable operation of the Interconnection as described in Section H.

   TOPs in the BCRC Area are required to follow Operating Instructions provided by the BCRC per BC MRS and operate to BC MRS to prevent the likelihood that a disturbance, action, or non-action in its Reliability Coordination Area will result in an SOL or IROL exceedance in another area of the Interconnection. When there is a difference in derived limits, the BCRC utilizes the most conservative limit until the difference is resolved.

3. **Operation under known and studied conditions and re-posturing without delay and no longer than 30 minutes** - The BCRC ensures that entities within its RC Area always operate under known and studied conditions and that they return their systems to a secure operating state following contingency events within approved timelines, regardless of the number of contingency events that occur or the status of their monitoring, operating and analysis tools. The BCRC also ensures its BA and TOPs re-posture the system to within all IROLs following contingencies within Tv or 30 minutes, whichever is shorter.

   The BCRC conducts next business day Operational Planning Analyses (OPA) utilizing planned outages, forecasted loads, generation commitment, and expected net interchange. The analyses include contingency analysis, voltage security analysis on key interfaces. These analyses model peak conditions for the day and are conducted utilizing Single Contingency (N-1) as well as credible Multiple Contingency analysis. The OPA
considers Operating Plans developed by BA and TOPs, and the BCRC will ensure that these plans get revised with additional mitigation actions as needed for potential exceedances determined in the next-day Operational Planning Analysis. Results and mitigation are documented in the next-day Operational Planning Analysis Report (OPA) and distributed to BCRC Reliability staff.

The BCRC OPA Report is posted on the BCRC Extranet secure web site for the BA and TOPs in the BCRC Reliability Coordination Area and neighbours to view and download. The BCRC OPA report includes significant generation outages, significant line outages, projected constraints, load forecast, generation unit commitments, and interchange schedules. The BCRC OPA is reviewed with TOPs, the BC Hydro BA, and neighbouring RCs where expected system conditions for the day are discussed, along with action required to mitigate any abnormal conditions. Additional conference calls are conducted with the same group when conditions warrant.

4. **Communicating SOLs and IROLs** – The BCRC monitors BES Facilities, the status of Remedial Action Schemes, and non-BES facilities identified as necessary by the BCRC, within its Reliability Coordinator Area and neighbouring Reliability Coordinator Areas to identify any SOL exceedances and to determine any IROL Limit exceedances within its Reliability Coordinator Area. The RC Operator is able to monitor the reliability and security of the BCRC Area through the monitoring of pre-contingency SOL and IROL exceedances identified by EMS alarms and State Estimator, and monitoring post-contingency SOL and IROL exceedances identified by Contingency Analysis results.

SOLs are established in the BCRC Area by Transmission Operators consistent with the BCRC’s System Operating Limit Methodology. The BCRC communicates IROLs within its wide-area view and provides updates to IROLs in reports, conference calls, and real-time via voice and messaging.

5. **BCRC process for issuing operating instructions** – The BCRC has implemented a communication protocol for the issuing/receiving of operating instructions. The BCRC issues operating instructions in a clear, concise and definitive manner. The BCRC ensures that the person receiving the operating instruction repeats the information back correctly, and acknowledges the response as correct or repeats the original statement again to resolve any misunderstandings. The BCRC’s process for issuing operating instructions is documented in 8T-11 Communication Protocols procedure.
**D. Next Day Operations**

This section documents how the BCRC conducts the next-day Operational Planning Analysis (OPA) for its Reliability Coordination Area.

**Reliability Analysis and System Studies** - The BCRC performs an OPA to assess planned operations for the next business day (and weekends/holidays that fall before the next business day) to ensure that the Bulk Power System can be operated reliably in pre- and post-contingency conditions. One study is typically performed for the entire BCRC Area.

Each business day and more often as required, the BCRC performs an OPA including equipment outages, forecast loads, generation commitments, and expected net interchange. All BES facilities and some non-BES facilities in the BCRC Area are monitored for all contingency cases and the base case. Base case flows on all monitored facilities are compared against their normal rating and pre-determined stability limits, and post-contingent flows for all monitored facilities are compared against their emergency rating. Voltage stability analysis is conducted on key critical interfaces to determine a flow limits.

The OPA considers Operating Plans developed by BA and TOPs. The BCRC will ensure that these plans get revised with additional mitigation actions as needed for potential exceedances identified in the next-day operational planning analysis. The BCRC will communicate with impacted entities to address potential exceedances immediately as they are identified.

**Information Sharing** – The BA, and TOPs in the BCRC Reliability Coordination Area and neighbouring RCs provide to the BCRC all information required for system studies, such as equipment outages, load forecast, generation unit commitments as per 8T-20 BCRC Data Specification and through data sharing agreements. The entities in the BCRC Reliability Coordination Area provide generation and transmission facility statuses per BCRC outage coordination requirements. BCRC Reliability Coordination Area load forecast is provided by the BC Hydro BA and is independently calculated in the BCRC EMS. Known interchange transactions involving the BCRC area are provided in the Western Interchange Tool (WIT).

**Sharing of Study Results** - The BCRC shares the results of its next-Day OPA with BCRC Reliability staff, entities within its Reliability Coordination Area and with other RCs. Study results for the next day up to and including the next business day typically are available no later than 14:00 Pacific Prevailing Time, unless circumstances warrant otherwise.

The next-day OPA is distributed to BCRC Reliability staff and is posted on the BCRC Extranet secure website for the BA/TOPs in the BCRC Reliability Coordination Area and neighbouring RCs to view and download.
E. Current Day Operations

This section documents how the RC conducts current-day reliability analysis for the RC area.

1. The BCRC uses a suite of real time network analysis tools to continuously monitor all Bulk Electric System (BES) and relevant Non-BES facilities within the BCRC Area and adjacent areas, as necessary, to ensure that the BCRC is able to determine any potential SOL and IROL violations within its Reliability Coordination Area.

The BCRC utilizes a state estimator, real-time contingency analysis and real-time voltage stability analysis as the primary tools to monitor facilities. The BCRC models all transmission elements in the BCRC Area operated at voltages greater than 25kV. The model also has extensive representation of neighbouring facilities in order to provide an effective wide-area view. The BC Hydro State Estimator Model currently includes over 8,000 buses. This model is typically updated weekly and may be updated on demand when deemed necessary.

Real Time Contingency Analysis (RTCA) is performed on approximately 700 contingencies, defined by BCRC engineering staff, using the state estimator model approximately every 4 minutes. Contingencies include all BES equipment and critical non-BES facilities in the BCRC Area and neighbouring contingencies that would impact facilities located within the BCRC Area. The actions from Remedial Action Schemes modeled within the EMS are included when RTCA contingencies are applied.

Real Time Voltage Stability Analysis (RTVSA) is performed on the 7 defined contingencies that make up the Interior-Lower Mainland path. RTVSA utilizes the most recent state estimator solution as its base case and provides updated results every 3-4 minutes.

SCADA alarming and RTCA pre-contingency results is utilized to alert the BCRC of any actual low of high voltages or facilities loaded beyond their normal or emergency limits.

In addition to the above applications, the BCRC uses several displays to maintain a wide area view for real-time and N-1 conditions. Transmission facilities assessed as critical are depicted on the e-terra vision overview for the BCRC Area and neighbouring areas. RTCA results as well as flows (MW and MVAR), indication of facilities out of service, and high/low voltage warning and alarming can be displayed on this overview. The RC Overview display monitors actual generation, frequency, and real and reactive reserves. The RC Voltage display monitors important substation voltages rated at 138kV and above. Substation one-line diagrams are used for station level monitoring and information.

As required by the RC to RC coordination agreements it has with its neighbouring RCs, the BCRC will make reasonable efforts to provide notice to a neighbouring RC if the BCRC identifies an operational concern in that RC’s area (e.g. declining voltages,
excessive reactive flows, or an IROL exceedance). The BCRC directs action to provide emergency assistance to all Reliability Coordination neighbours, during declared emergencies, which is required to mitigate the operational concern to the extent that the same entities are taking in kind steps and the assistance would be effective.

2. The BCRC maintains awareness of the status of all current critical facilities whose failure, degradation or disconnection could result in an SOL or IROL exceedance within its Reliability Coordination Area via State Estimator, RTCA, SCADA alarming, and transmission displays. The BCRC is aware of the status of any facilities that may be required to assist Reliability Coordination Area restoration objectives via these same displays and tools.

3. The BCRC is continuously aware of conditions within its Reliability Coordination Area and includes this information in its reliability assessments via automatic updates to the state estimator, e-terra vision, and transmission displays. The BCRC monitors its Reliability Coordination Area parameters, including the following:

3.1 Current status of Bulk Electric System elements (including critical auxiliaries such as Automatic Voltage Regulators), and system loading are monitored by state estimator, RTCA, SCADA Alarming, e-terra vision, and transmission displays. TOPs are required to report to the BCRC when Automatic Voltage Regulators are not in-service and when Remedial Action Schemes are not available or degraded or the corresponding teleprotection fails.

3.2 Current pre-contingency element conditions (voltage, thermal, or stability) are monitored by state estimator, SCADA Alarming, e-terra vision, and transmission displays.

3.3 Current post-contingency element conditions (voltage, thermal, or stability) are monitored by RTCA, e-terra vision and transmission displays.

3.4 System real reserves are monitored versus required on the RC Overview display. Reactive reserves versus required are monitored via monitoring adequacy of calculated post-contingent steady state voltages versus voltage limits, voltage stability interfaces against limits, and reactive reserves versus required when applicable.

3.5 Capacity and energy adequacy conditions - via monitoring reserve requirements and regional reporting.

3.6 Current ACE for the Balancing Area is displayed on a BAAL chart to the BCRC. When ACE exceeds BAAL the operating point will be depicted outside the BAAL limits and the RC Operator will receive an alarm.
3.7 Planned generation dispatches for the BCRC Area are provided to the BCRC in the form of the unit commitment plan.

3.8 Planned transmission or generation outages are reported to the BCRC via the Control Room Operating Window (CROW) application.

Contingency Events are monitored by state estimator, RTCA, SCADA Alarming, eTerra Vision, and transmission displays. The BA and TOPs are required to report Contingency Events to the BCRC.

4. The BCRC monitors Bulk Power System parameters that may have significant impacts upon its Reliability Coordination Area and neighboring Reliability Coordination areas with respect to:

4.1 The BCRC maintains awareness of all Interchange Transactions that wheel-through, source, or sink in its Reliability Coordination via NERC E-tags and OATI displays. Interchange Transaction information is made available to all RCs via NERC E-tags.

4.2 The BCRC evaluates and assesses any additional Interchange Transactions that would exceed IROL or SOLs by comparing current system conditions and limits to RTCA results. As flows approach their IROL or SOLs, the BCRC evaluates the incremental loading next-hour transactions would have on the SOLs or IROLs and determines if action needs to be taken to prevent an SOL or IROL exceedance. The BCRC has the authority to direct all actions necessary and may utilize all resources to address a potential or actual IROL exceedance up to and including load shedding.

4.3 The BCRC monitors the BC Balancing Area Operating Reserves versus required to ensure the required amount of Operating Reserves are provided and available as required to meet NERC Control Performance Standards. The BCRC is alerted if reserves fall below required. If necessary, the BCRC will direct the Balancing Area to replenish reserves including obtaining assistance from neighbours as needed.

4.4 The BCRC identifies the cause of potential or actual SOL or IROL exceedances via analysis of state estimator results, RTCA results, SCADA Alarming of outages, transmission displays of changes, and Interchange Transaction impacts. The BCRC will initiate control actions including transmission switching, generation redispatch, and/or emergency procedures to relieve the potential or actual IROL exceedance without delay, and no longer than 30 minutes. The BCRC is authorized to direct utilization of all resources, including load shedding, to address a potential or actual IROL exceedance.

4.5 The BCRC communicates start and end times for time error corrections to the Balancing Authority within its RC Area. The BCRC communicates Geo-Magnetic Disturbance forecast information to BAs, TOPs, and will assist in development of any
required response plan. The BCRC uses a dedicated messaging system to communicate timer error correction and GMD forecast information to its Balancing Authority.

4.6 The BCRC participates in NERC Hotline discussions, assists in the assessment of reliability of the Regions and the overall interconnected system, and coordinates actions in anticipated or actual emergency situations. The BCRC will disseminate this information within its area as appropriate.

4.7 The BCRC monitors system frequency and its Balancing Authority’s performance and will direct any necessary rebalancing required for the BA to return to CPS and Disturbance Control Standard (DCS) compliance. The BCRC receives a visual indication when ACE exceeds BAAL and/or L10. When necessary, the BCRC directs the Balancing Authority to return to within BAAL and/or L10. The BCRC will direct its BA to utilize all resources, including firm load shedding, as necessary to relieve an emergency condition. The NWPP Reserve Sharing program is normally the resource used by the BCRC’s Balancing Authority to relieve an emergency condition associated with CPS and DCS compliance.

4.8 The BCRC coordinates with neighbouring RCs, BAs and TOPs, as needed, on the development and implementation of Operating Plans, Procedures, and Processes to mitigate potential or actual SOL and IROL exceedances. The BCRC coordinates pending generation and transmission maintenance outages with other RCs, as necessary, in both the real-time and next-day reliability analysis timeframes. The BCRC participates in periodic conference calls with neighbouring RCs as necessary.

4.9 The BCRC will assist its BA in arranging for assistance from neighboring RCs or Balancing Authorities via the Energy Emergency Alert (EEA) notification process and will conference parties together as appropriate.

4.10 The BCRC monitors the BC Balancing Authority to identify the sources of large ACE that may be contributing to frequency, time error, or inadvertent interchange and directs corrective actions with its Balancing Authority.

4.11 The TOPs within the BCRC Reliability Area must inform the BCRC of all changes in status of Remedial Action Schemes (RAS) including any degradation or potential failure to operate as expected by the TOP. The BCRC factors these RAS changes into its reliability analyses.

5. The BCRC issues alerts, as appropriate, to its BA and TOPs when it foresees a transmission problem (such as an SOL or IROL exceedance, loss of reactive reserves, etc.) within its Reliability Area that requires notification. The BCRC issues alerts, as appropriate, to all RCs via the Reliability Coordinator Information System when it foresees a transmission problem (such as an SOL or IROL exceedance, loss of reactive reserves, etc.) within its Reliability Area that requires notification.
6. The BCRC confirms Real-time Assessment results via analyzing results of state estimator/RTCA, and discussions with local TOPs and neighbouring RCs. The BCRC identifies options to mitigate potential or actual SOL or IROL exceedances via examining existing operating plans, system knowledge, and power flow analysis to identify and implement only those actions as necessary as to always act in the best interests of the interconnection.
F. Emergency Operations

The BCRC utilizes the BCRC Emergency Operating Procedures, posted on the BCRC extranet site, to return the transmission system to within any applicable IROLs within the required mitigation times.

The BCRC Emergency Operating Procedures document the processes and procedures the BCRC follows when directing its BA and TOPs to re-dispatch generation, reconfigure transmission, manage Interchange Transactions, or shed firm load, to return the system to a reliable state. The BCRC coordinates its alert and emergency procedures with other RCs via seam coordination agreements listed in Section H.

The BCRC will monitor system frequency and its Balancing Authority’s performance. If the BCRC determines that its BA is contributing to a frequency excursion, the BCRC will direct the BA to use all resources available, including load shedding, to comply with CPS and Contingency Reserve requirements.

The BCRC utilizes the BCRC Emergency Operating Procedures when it is experiencing a potential or actual Energy Emergency within its BA, Reserve-Sharing Group, or Load-Serving Entity within its Reliability Coordination Area. The BCRC Emergency Operating Procedures document the processes and procedures the BCRC uses to mitigate the emergency condition, including a request for emergency assistance if required.
G. System Restoration

1. **Knowledge of members’ Restoration Plans** - The BCRC is knowledgeable of the restoration plans of each of the Transmission Operators in its RC Area and has a written copy of each plan in its possession. The BCRC verifies that the most current plans are on file on an annual basis. Additionally, the BCRC Reliability Coordinators are trained on individual plans during regular training sessions.

   During system restoration, the BCRC monitors restoration progress and acts to coordinate any needed assistance.

2. **BCRC Restoration Plan** - The BCRC Restoration Plan includes all BAs and TOPs in its Reliability Coordination Area. The BCRC takes action to restore normal operations once an operating emergency has been mitigated in accordance with its Restoration Plan. This Restoration Plan is drilled at least annually.

   The BCRC approves, communicates and coordinates the re-synchronizing of major system islands or synchronizing points so as not to cause a burden on member or adjacent Reliability Coordination Areas.

3. **Dissemination of Information** - The BCRC will disseminate information regarding restoration to neighbouring RCs and BAs/TOPs not immediately involved in restoration by posting pertinent information on the RCIS and/or via direct phone call. The BCRC will also use the NERC Hotline for periodic updates to other RCs if required.
H. Coordination Agreements and Data Sharing

Coordination Agreements:

The BCRC has executed RC coordination agreements with:

1. Alberta Electric System Operator (AESO)
2. Peak Reliability (Peak)
3. California Independent System Operator (RC West/CAISO)

Data Sharing - The BCRC determines the data requirements to support its reliability coordination tasks and requests such data from entities internal and external to B.C., including adjacent RCs. The BCRC provides for data exchange with entities internal and external to B.C. and adjacent Reliability Coordinators via a secure network. Entities subject to data requests provide data to BCRC via mutually agreeable transfer methods identified in the BCRC’s IRO-010 Data Specification. BCRC provides data to entities outside BCRC via direct links and mutually agreeable transfer methods identified in IRO-010 Data Specifications.
I. Facility

The BCRC performs the RC function at the BC Hydro Fraser Valley Office (FVO) located in Langley, British Columbia. FVO has the necessary facilities for the BCRC to perform their responsibilities. The backup facility, in nearby Surrey, BC provides the functional workspace for personnel to perform the Reliability Coordinator function. The FVO and Back Up Control Centre (BUCC) have the necessary voice and data communication links to appropriate entities within the BCRC Area to perform their responsibilities. These communication facilities are staffed and available to act in addressing a real-time emergency condition.

1. Adequate Communication Links – The BCRC has adequate, redundant telecommunications circuits providing both voice and data connectivity with its members. The BCRC maintains satellite phones, Voice over IP phones, cell phones, and redundant, diversely routed telecommunications circuits.

2. Multi-directional Capabilities – The BCRC has multi-directional communications capabilities with its members, and with neighbouring RCs, for both voice and data exchange to meet reliability needs of the Interconnection.

3. Real-time Monitoring - The BCRC RC has detailed real-time monitoring capability of its Reliability Coordination Area and extensive representation of neighbouring facilities to ensure that potential or actual System Operating Limit or Interconnection Reliability Operating Limit exceedances are identified.

   The BCRC monitors Bulk Power System elements (generators, transmission lines, buses, transformers, breakers, etc.) that could result in SOL or IROL exceedances within its Reliability Coordination Area. The BCRC monitors both real and reactive power system flows, and operating reserves, and the status of the Bulk Power System elements that are, or could be, critical to SOLs and IROLs and system restoration requirements within its Reliability Coordination Area.

4. Study and Analysis Tools

4.1 The BCRC has adequate analysis tools, including state estimation, pre-and post-contingency analysis capabilities (thermal, stability, and voltage), and wide-area overview displays. The BCRC has detailed monitoring capability of the BCRC Reliability Area and sufficient monitoring capability of the surrounding Reliability Areas to ensure potential reliability issues are identified. The BCRC continuously monitors key transmission facilities in its area in conjunction with the Members monitoring of local facilities and issues.

   The BCRC ensures that SOL and IROL monitoring and derivations continue if the main monitoring system is unavailable. The BCRC has backup facilities that shall be exercised if the main monitoring system is unavailable.
The systems used by the BCRC include:

- State Estimator and Contingency Analysis
- Status and Analog Alarming
- Overview Displays of the BCRC Transmission System
- One line diagrams for the entire BCRC Transmission System
- Transient Stability Analysis (TSA-PM)
- Voltage Security Assessment (VSA)

The BCRC utilizes these tools, which provide information that is easily understood and interpreted by the BCRC operating personnel. The alarm management is designed to classify alarms in priority for heightened awareness of critical alarms.

4.2 The BCRC controls its RC analysis tools, including approvals for planned maintenance. The BCRC has procedures in place to mitigate the effects of analysis tool outages.
J. Staffing

Staff Adequately Trained and NERC Certified – The BCRC maintains trained RCs on duty at all times. In addition, one or more Reliability Coordinator Engineers are on shift from 8:00 AM to 4:00 PM M-F. The BCRC staffs all operating positions that meet the following criteria with personnel that are NERC-certified for the applicable functions:

- Positions that have the primary responsibility, either directly or through communications with others, for the real-time operation of the interconnected Bulk Power System.
- Positions directly responsible for complying with B.C. MRS and NERC Standards.

The BCRC operating personnel all complete training using realistic simulations of system emergencies, in addition to other training required to maintain qualified operation personnel.

Comprehensive Understanding - The BCRC operating personnel have an extensive understanding of the BA and TOPs within the BCRC Reliability Coordination Area, including the operating staff, operating practices and procedures, restoration priorities and objectives, outage plans, equipment capabilities, and operational restrictions.

The BCRC operating personnel place particular attention on SOLs and IROLs and inter-tie facility limits. The BCRC ensures protocols are in place to allow BCRC operating personnel to have the best available information at all times.

The BCRC’s System Operator Training process describes the process by which System Operations personnel are trained to perform their duties, both at entry level and in continuous training status. The BCRC also uses the Operator Training Manual to establish training and documentation requirements for System Operators in the form of position specific curricula, NERC certification Guidelines, On-the-Job qualification Guides, and Technical Qualification Training Checklists. The Technical Qualification Training Checklists contain competencies for the RC System Operator position and other operation positions. An analysis of each operator position was conducted by Subject Matter Experts (SME), Management, and training representatives to develop the checklists. These checklists provide a way to identify, track status, and document completion of required initial training for any new System Operator.

Standards of Conduct – The BCRC operates independently of BC Hydro marketing function employees and BC Hydro’s wholly owned market subsidiary, Powerex Corp. The BCRC also operates independently from the BC Hydro BA and TOP. RC Operators do not pass information or data to any marketing function employees that is not made publicly available. The BCRC staff has completed training on the BC Hydro RC Standards of Conduct and on the Transmission Standards of Conduct. Refresher training on both BC Hydro Standards of Conduct is conducted every year. Training records are maintained.
Appendix A – BCRC Governing Documents

1. Reliability Coordinator Standards of Conduct
2. Reliability Coordinator Registered Entities Oversight Group Terms of Reference
3. Reliability Coordinator BA/TOP Operations Working Group Terms of Reference
CAISO-RC West Coordination Plan

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Introduction

The North American Electric Reliability Corporation (NERC) requires every Region, sub-region, or interregional coordinating group to establish a Reliability Coordinator to provide the reliability assessment and emergency operations coordination for the Balancing Authorities and Transmission Operators within the Regions and across the Regional boundaries.

California ISO Reliability Coordinator (RC WEST) serves as the reliability coordinator (RC) for Balancing Authority (BA) customers and the Transmission Operating (TOP) customers in their respective BA Areas. The RC WEST functions associated with the reliability of the Bulk Electric System (BES) include:

- Review and approval of planned facility, transmission line outages and generation outages based upon current and projected system conditions,
- Monitoring facilities within its Reliability Coordination Area and neighboring Reliability Coordination areas to identify any System Operating Limit (SOL) exceedances and to determine any Interconnection Reliability Operating Limit (IROL) exceedances within its Reliability coordination area, and
- Issuing Operating Instructions to ensure reliability of the BES is maintained.

RC WEST procedures and policies are consistent with NERC and WECC Regional Reliability Organization (RRO) Standards.

1. Responsibilities – Authorization

1.1. Authority to Act - RC WEST is responsible for the reliable operation of the BES within its Reliability Coordination Area, in accordance with NERC Standards and Regional policies and standards. RC WEST’s authority to act is derived from a set of agreements that all RC WEST members have executed (See Appendices A and C).

1.2. Decision Making Authority - RC WEST has clear decision-making authority to act and to direct or instruct members within its Reliability Coordination Area to take action to preserve the integrity and reliability of the BES. RC WEST’s responsibilities and authorities, as well as its members’ responsibilities, are clearly defined in the governing documents.

1.3. Wide Area view of its Reliability Coordination Area - RC WEST has a Wide Area view of its Reliability Coordination Area and neighboring areas that have an impact on RC WEST’s area. The RC WEST has the operating tools, processes and procedures (including the authority) to prevent or mitigate emergency operating situations in both next-day analysis and during real-time conditions, per the NERC Standards and Regional policies and standards, as well as the governing documents listed in Appendix A of this document.

1.4. Independence - RC WEST will act in the best interest of insuring reliability for its Reliability Coordination Area and the Western Interconnection, before that of any other entity. This expectation is clearly identified in the governing documents (see Appendix A).

1.5. RC WEST Operating Instruction Compliance - Per the governing documents (see Appendix A), the participating control centers shall carry out required emergency actions as directed or instructed by the RC WEST, including the shedding of firm load if required, unless such actions would violate safety, equipment, regulatory, or statutory requirements.
2. Responsibilities – Delegation of Tasks

2.1. RC WEST has not delegated any Reliability Coordination tasks.

3. Common Tasks for Next-Day and Current-Day Operations

3.1. This section documents how RC WEST conducts current-day and next-day reliability analysis for its Reliability Coordination Area.

3.2. Determination of Interconnection Reliability Operating Limits (IROLs) – RC WEST established IROLs in accordance with its SOL methodology.

3.3. During real-time operations, the RC WEST continuously ensures that the system is resilient and not in danger of cascade failure due to Thermal Cascading (monitored through Real Time Contingency Analysis [RTCA]), Voltage instability (monitored through Voltage Stability Analysis [VSA]) and Dynamic Transient Instability (monitored through Real-Time Dynamic Stability Assessment [RT-DSA]).

3.4. RC WEST monitors and acts to prevent the likelihood of a SOL or IROL exceedance in its own area or other areas of the Interconnection, and coordinates with impacted Reliability Coordinators when there is a difference in limits. RC WEST, through the agreements with other Reliability Coordinator neighbors, will coordinate operations to prevent the likelihood of a SOL or IROL in another area. The scope of these agreements includes data exchange and Outage Coordination. (See Appendix B.)

3.5. BA and TOP customer control centers in the RC WEST Area must follow Operating Instructions provided by RC WEST. NERC Standards are followed to prevent the likelihood that a disturbance, action, or non-action in its Reliability Coordination Area will result in a SOL or IROL exceedance in its own area or other areas of the Interconnection. When there is a difference in derived limits between RCs, the RC WEST utilizes the most conservative limit until the difference is resolved.

3.6. Operate under known and studied conditions and reposition without delay and within no longer than 30 minutes following Contingency events or operational situations that require such action – The RC WEST will perform real-time analysis at least once every 30 minutes. Under normal circumstances, the RC WEST will perform real-time analysis after every 5 minute RTCA and VSA run, and after every 15 Minute RT-DSA run. This provides assurance that entities within its Reliability Coordination Area always operate under known and studied conditions and that they return their systems to a secure operating state following Contingency events, within approved timelines. RC WEST also ensures that entities within its Reliability Coordination Area operate the system to be within all IROLs following Contingencies, within 30 minutes.

3.7. On a daily basis, RC WEST conducts Operations Planning Analysis, factoring in planned outages, forecasted loads, generation commitment, and expected net interchange. The analyses include Contingency analysis and voltage stability analysis on key interfaces. These analyses model each operating hour of the day, and include assessment of anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations.
3.8. Results and mitigation are documented in the Day Ahead Reliability Analysis (DARA) report and made available for review, to RC WEST staff and entities within the RC WEST Reliability Coordinator Area and neighboring Reliability Coordinators. Mitigation plans are formed as needed for potential SOL and IROL exceedance determined in the DARA.

3.9. In real-time, RC WEST relies on its telemetry and real-time analysis tools to monitor the real-time system conditions to identify potential IROL and SOL exceedance. RC WEST’s operational philosophy is to monitor and initiate operating plans for all SOL exceedances identified through Real Time Assessment, which include assessment of existing (pre-Contingency) and potential (post-Contingency) operating conditions. RC WEST communicates about IROLs within its RC Area and provides updates as needed via reports, morning conference calls, and in real-time, via voice and messaging.

3.10. RC WEST process for issuing Operating Instructions – RC WEST uses a number of communication tools for issuing/receiving of Operating Instructions. The primary communication means is the RC WEST Turret Phone system, which is a dedicated telephone-based system. The RC WEST will also employ a “Grid Messaging System” that sends instructions/message(s) to all control centers simultaneously, and confirms response. RC WEST communicates Operating Instructions in a clear, concise and definitive manner. When appropriate, three-part communication will be required to ensure the communications are correctly received and understood.

4. Next Day Operations

4.1. This section documents how RC WEST conducts Operational Planning Analysis for its Reliability Coordination Area.

4.2. Reliability Analysis and System Studies – RC WEST conducts Operational Planning Analysis for its Area to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations, and to ensure that the BES can be operated reliably in normal and post-Contingency conditions.

4.3. On a daily basis, RC WEST conducts Operational Planning Analysis, utilizing known outages, forecasted loads, generation commitment and dispatch, and expected net interchange, employing the study capability in the RC WEST Network Applications. Base case flows on all monitored facilities are compared against the normal continuous rating. Post-Contingency flows for all monitored facilities are compared against their Emergency rating for all Contingencies. Voltage stability analysis is conducted on key critical interfaces to determine stability limit.

4.4. RC WEST coordinates mitigation plans as needed for potential SOL exceedance determined in the Operational Planning Analysis. Mitigation can include additional generation commitment, system reconfiguration, generation re-dispatch, outage postponement or other local flow mitigation procedures.

4.5. Information Sharing – BAs and TOPs in the RC WEST Area and neighboring Reliability Coordinator areas provide RC WEST with all information required for system studies, such as critical facility status, load, generation, Contingency Reserve projections and known interchange transactions.

4.6. The entities in the RC WEST Area provide expected generation and transmission facility status to the RC WEST outage scheduling application, including forecasted loads, operating
reserves, and known interchange transactions. RC WEST provides this information through a secure network to applicable members.

4.7. Sharing of Study Results - RC WEST makes available the results of its system studies with the entities within its Reliability Coordination Area and/or with other Reliability Coordinators. RC WEST intends to make study results available for the next day by no later than 16:00 Pacific Prevailing time, unless unforeseen circumstances prevent this.

4.8. Day Ahead Reliability Analysis Report (DARA) - Made available to RC WEST and neighboring Reliability Coordinators. RC WEST holds daily conference calls as necessary, with participating members and others as part of this process.

5. Current-Day Operations

5.1. This section documents how RC WEST conducts Real-Time reliability analysis for its Reliability Coordination Area.

5.2. RC WEST uses a suite of real-time network analysis tools to continuously monitor all BES facilities within the RC WEST Area and adjacent areas, including sub-transmission information as needed, to ensure that RC WEST is able to proactively maintain system reliability. RC WEST makes every effort to prevent any expected or potential SOL and IROL exceedance within its Reliability Coordination Area.

5.3. RC WEST uses both a state estimator and RTCA as the primary tools to monitor facilities. The state estimator model includes all facilities in the WECC BES, as well as facilities in the RC WEST Area. The model also includes extensive representation of neighboring facilities, in order to provide an effective wide-area view, and is updated as required to maintain accurate modelling.

5.4. RTCA is performed on Contingencies using the state estimator model approximately every five minutes. Contingencies include all RC WEST Area equipment and facilities and also any neighboring RC area equipment that is known to impact the RC WEST area.

5.5. In order to continuously monitor its voltage stability limited interfaces, RC WEST uses VSA, a real-time calculation tool. VSA takes a state estimator snapshot and calculates a voltage collapse equivalent flow for the interface, based on current real-time telemetry and topology. A VSA Transfer Limit is established as the limit to prevent a potential post-Contingency voltage instability, and RC WEST operates to maintain flows below the limit.

5.6. RC WEST uses SCADA alarming to warn of any actual low or high voltages, or facilities loaded beyond their normal or emergency limits.

5.7. In addition to the above-mentioned applications, RC WEST uses dynamically updated transmission overview displays to maintain a wide area view. All transmission facilities 220 kV and above are depicted on the overview with flows (MW and MVAR), indication of facilities out of service, high and low voltage warning and alarming. For more detailed monitoring, RC WEST uses bus level one-line diagrams for station level monitoring and information. The one-line diagrams are populated with the real-time telemetered information, as well as the state-estimated solution.

5.8. RC WEST notifies neighboring Reliability Coordinators of operational concerns (e.g. declining voltages, excessive reactive flows, or IROL exceedance) that it identifies within the neighboring Reliability Coordination Area, via direct phone calls, conference calls, NERC hotline calls, and/or RCIS messages. RC WEST has joint operating agreements with
neighboring Reliability Coordinators (listed in Appendix B) to provide emergency assistance during declared emergencies.

5.9. RC WEST uses State Estimator, RTCA, SCADA alarming, transmission and summary displays to maintain awareness of the status of all current critical facilities whose failure, degradation or disconnection could result in an SOL or IROL exceedance within its Reliability Coordination Area. These same displays and tools keep RC WEST informed of the status of any facilities that may be required to assist Reliability Coordination Area restoration objectives.

5.10. RC WEST is continuously aware of conditions within its Reliability Coordination Area, and includes real-time information in its reliability assessments, via automatic updates to the state estimator, VSA, and transmission displays. RC WEST monitors its Reliability Coordination Area parameters, including the following:

5.10.1. Current status of BES elements (transmission or generation including critical auxiliaries) such as:
  - Automatic Voltage Regulators,
  - Remedial Action Schemes (RAS) and
  - System loading (monitored by state estimator, RTCA, SCADA Alarming and transmission displays).

RC WEST members are required to report to RC WEST any status changes to RAS or when Automatic Voltage Regulators are not in service.

5.10.2. Current pre-Contingency element conditions (voltage, thermal, or stability) – are monitored by state estimator, SCADA Alarming, RTCA transmission and summary displays.

5.10.3. Current post-Contingency element conditions (voltage, thermal, or stability) – are monitored by RTCA, VSA, DSA and transmission displays.

5.11. RC WEST monitors the availability and deployment of reactive reserves, by monitoring post-Contingent steady state voltages. Reactive Reserve inquiries are made as needed with applicable parties when reactive reserves in real-time appear inadequate or lower than expected.

5.12. Capacity and energy conditions for all RC WEST participants are determined in Day Ahead (DA) and monitored in real-time, in accordance with RC WEST Reliability Processes.

5.13. The RC WEST monitors current BA ACEs and System Frequency trends. This information is used to ensure that a participating BA’s failure to adhere to NERC BAAL Control Standards is not contributing to reliability-related issues. This includes IROL/SOL exceedances or capacity-related issues. If failure to conform to BAAL standards is contributing to an IROL exceedance, the RC WEST will order the use of all resources, including firm load shedding, to relieve the exceedance.

5.14. Planned transmission or generation outages are reported to RC WEST via the Outage Management System (OMS) or other outage reporting applications as agreed to with participants. This outage information, once approved and implemented, automatically or manually updates the Full Network model.

5.15. State estimator, RTCA, SCADA Alarming, and transmission displays monitor Contingency Events. Member control centers report Contingency Events on non-monitored facilities, if needed, to RC WEST.
5.16. RC WEST monitors BES parameters that may have significant impacts upon its Reliability Coordination Area and neighboring Reliability Coordination areas with respect to:

5.16.1. RC WEST monitors all BES facilities within its RC area for current and projected loadings. If reliability impacts are expected or are occurring, the RC WEST may utilize all available resources, up to and including load shedding, to address a potential or actual IROL exceedance. The RC WEST has EMS displays, which allow RC operators to watch and monitor all IROL limits.

5.16.2. RC WEST monitors participating BA’s and Reserve Sharing Groups’ (RSG) Contingency Reserve Actual (CRA) versus their Contingency Reserve Obligation (CRO) to ensure the necessary amounts of Operating Reserves are available as required to meet NERC BAL and EOP Standards. If needed, the RC WEST will undertake Energy Emergency Alert (EEA) procedures or assist with obtaining additional reserves from neighbors.

5.16.3. RC WEST identifies the cause of potential or actual SOL or IROL exceedance via analysis of state estimator results, RTCA results, VSA results, DSA results, SCADA Alarming of outages, transmission displays of changes, and Interchange Transaction impacts. RC WEST will direct or instruct actions including transmission reconfiguration, generation re-dispatch, or emergency procedures to relieve the potential or actual IROL exceedance without delay, and in no longer than 30 minutes. RC WEST is authorized to direct utilization of all resources, including load shedding, to address a potential or actual IROL exceedance.

5.17. RC WEST communicates Geo-Magnetic Disturbance forecast information to participating BAs and TOPs via the RC WEST Messaging tool. RC WEST will assist in development of any required response plan and may move to conservative operating mode to mitigate impacts as needed.

5.18. RC WEST initiates NERC Hotline discussions, to assist in the assessment of reliability of the Regions and the overall interconnected system, and coordinates actions in anticipated or actual emergency situations. RC WEST will disseminate this information via the RC WEST Messaging tool or by individual phone calls.

5.19. RC WEST coordinates, on an as-needed basis, with other Reliability Coordinators and member BAs and TOPs on the development and implementation of action plans to mitigate potential or actual SOL, IROL, BAAL or DCS/BCE exceedance.

5.20. The participating BAs and TOPs within the RC WEST Reliability Area inform RC WEST of all changes in status of RAS, including any degradation or potential failure to operate as expected. RC WEST factors these RAS changes into its reliability analyses and updates its Contingency definitions as appropriate.

5.21. RC WEST confirms reliability assessment conclusions by analyzing results of state estimator/RTCA and discussions with participating BAs and TOPs and neighboring Reliability Coordinators. RC WEST identifies options to mitigate potential or actual SOL or IROL exceedance by examining existing operating procedures, system knowledge, and power flow analysis to identify and implement only those actions necessary to act in the best interests of the interconnection.

6. Emergency Operations
6.1. RC WEST applies operating procedures, RC0310 - Mitigating SOL and IROL Exceedances and RC00410 - System Emergencies (See appendix D), to direct or instruct its TOPs to return the transmission system to within SOL or IROL limits as soon as possible, but no longer than within 30 minutes, to prevent a single or credible multiple Contingency from resulting in instability, uncontrolled separation, or Cascading Outages that adversely impact the reliability of the BES. These actions may include: reconfiguration, re-dispatch, load transfer, schedule curtailment, controllable device operation or load shedding. Load shedding will be considered a last resort to mitigate reliability issues that occur in real-time.

6.2. RC WEST will use RC0310 - Mitigating SOL and IROL Exceedances and/or RC0410 - System Emergencies (See appendix D) when it determines that IROL exceedances are imminent. RC WEST procedures document the processes that RC WEST follows when directing or instructing BAs and TOPs in the actions to be taken to mitigate the IROL exceedance to return the system to a reliable state. RC WEST coordinates its emergency procedures with other Reliability Coordinators, per Appendix B.

6.3. RC WEST directs or instructs BAs and TOPs to take actions in the event the loading of transmission facilities progresses to, or is projected to progress to, a SOL or IROL exceedance. Corrective actions may include: reconfiguration, re-dispatch and/or load shedding to prevent or relieve SOL or IROL exceedance. RC WEST will not rely on, nor wait for, the Qualified Transfer Path Unscheduled Flow (USF) procedure to relieve IROL exceedance. RC WEST will assist with coordination of the USF procedure, if doing so will provide additional relief. RC WEST will adhere to the USF procedure instructions, including curtailing transactions.

6.4. RC WEST utilizes RC0410 - System Emergencies (See appendix D) to mitigate an Energy Emergency within its Reliability Coordination Area. RC WEST will provide assistance to other Reliability Coordinators, per its respective joint operating agreement listed in Appendix B.

6.5. RC WEST utilizes RC0410 - System Emergencies (See appendix D) when it, or a BA or TOP within its Reliability Coordination Area is experiencing a potential or actual Energy Emergency. RC WEST Emergency Operations document the processes and procedures that RC WEST uses to mitigate the emergency condition, including a request for emergency assistance if required.

6.6. RC WEST will coordinate drills and simulations on a regular basis to reinforce competencies required for implementation of Emergency procedures.

7. System Restoration

7.1. Knowledge of RC WEST Area TOP Restoration Plans – RC WEST is aware of each TOP’s System Restoration Plan and has a written copy of each plan. During system restoration, RC WEST monitors restoration progress and acts to coordinate any needed assistance. RC WEST will coordinate the restoration activities, depending on system conditions.

7.2. System Restoration Plan – The RC WEST Restoration protocols are contained in the RC System Restoration Plan. Following a Disturbance in which one or more areas within the RC WEST Area become isolated or blacked out, the RC WEST System Operators will implement the RC WEST Restoration Plan. The scope of the RC WEST’s Restoration Plan ends when all of the TOPs in the RC WEST Area are interconnected, each TOP has transferred authority back to its respective BA(s), the RC WEST Area is interconnected to its
RC West Coordination Plan

neighboring RC Areas and normal operations can be resumed. This Restoration Plan is
drilled at least annually or more frequently, as needed.

7.3. Dissemination of Information - RC WEST serves as the primary contact for disseminating
information regarding Restoration to neighboring Reliability Coordinators and members not
immediately involved in Restoration.

7.4. Restoration - RC WEST approves, communicates and coordinates the re-synchronizing of
major system islands or synchronizing points so as not to cause a burden on member or
adjacent Reliability Coordination Areas.

8. Coordination Agreements and Data Sharing

8.1. Coordination Agreements: See Appendix B

8.2. Data Sharing - RC WEST determines the data requirements to support its Reliability
Coordination tasks and requests such data from members or adjacent Reliability
Coordinators. RC WEST provides for data exchange with participating BAs and TOPs and
adjacent Reliability Coordinators via a secure network. RC WEST members provide data to
RC WEST via mutually agreeable transfer methods identified in the RC WEST’s IRO-010
Data Specification. RC WEST provides data to entities outside RC WEST via direct links
and mutually agreeable transfer methods identified in IRO-010 Data Specifications.

9. Facility

9.1. Business Continuity-RC WEST performs the Reliability Coordinator function at the California
ISO Headquarters in Folsom, CA, along with the CAISO control center in Lincoln, CA. The
Folsom and Lincoln control centers have the necessary voice and data communication links
to appropriate entities within RC WEST Reliability Area to perform their responsibilities.
These facilities are staffed 24x7, and are available to act in addressing a real-time
emergency condition.

9.2. Adequate Communication Links - RC WEST maintains satellite phones, cellular phones,
and redundant, diversely-routed telecommunications circuits. There is also a video link
between the Folsom and Lincoln Control Rooms.

9.3. Multi-directional Capabilities – RC WEST has multi-directional communications capabilities
with its members and neighboring Reliability Coordinators, to meet reliability needs of the
Interconnection, for both voice and data exchange.

9.4. Real-time Monitoring – RC WEST has detailed capability for real-time monitoring of its
Reliability Coordination Area and Reliability Coordinators adjacent to the RC WEST
Reliability Coordination Area, to ensure that potential or actual SOL or IROL exceedance is
identified. RC WEST monitors BES elements (generators, transmission lines, buses,
transformers, breakers, etc.) that could result in SOL or IROL exceedance within its
Reliability Coordination Area. RC WEST monitors both real and reactive power system
flows, operating reserves, and the status of the Bulk Power System elements that are, or
could be, critical to SOLs and IROLs and system restoration requirements within its
Reliability Coordination Area.
9.5. Study and Analysis Tools - RC WEST has adequate analysis tools, including state estimation, pre-and post-Contingency analysis capabilities (thermal, stability, and voltage), and wide-area overview displays. RC WEST has detailed monitoring capability of the RC WEST Reliability Area and sufficient monitoring capability of the surrounding Reliability Areas to ensure potential reliability issues are identified. RC WEST continuously monitors key transmission facilities in its area in conjunction with the Members’ monitoring of local facilities and issues.

The systems RC WEST uses include:

- **Energy Management System (EMS)/Supervisory Control and Data Acquisition (SCADA) System:**
  - EMS provides the RC operator with real-time monitoring and visibility of the status of BES transmission and generation facilities, RASs, non-BES facilities that impact the BES, and other critical real-time parameters for the reliable operation of the BES. The EMS system also provides alarming of critical events that affect the reliability of the BES.

- **State Estimator (SE):**
  - This is an application that performs numerical analysis of the real-time network model and data to determine the system’s current condition. The SE can typically identify bad analog telemetry, estimate non-telemetered flows and voltages and determine real time operating limit exceedances. The SE runs every 5 minutes, and provides a base-case solution used by RTCA and VSA applications.

- **Real-time Contingency Analysis (RTCA):**
  - This is a primary Real-time Assessment application that runs every 5 minutes and automatically performs analyses of all identified single and credible multiple Contingencies that affect the RC Area. The RC operator uses the results to identify potential post-Contingency thermal or voltage exceedances on the system and to proactively develop mitigation plans to ensure reliability.

- **Real-time Voltage-Stability Analysis (VSA):**
  - This application runs every 5 minutes and performs voltage-stability analyses of predetermined stability limitations on the system to determine voltage-stability limits and margins for those interfaces.

- **Real-time Dynamic Stability Analysis (RT-DSA):**
  - This application runs every 15 minutes and performs transient stability analyses of predetermined stability limitations on the system to identify transient-stability limits and margins for those interfaces.

- **Plant Information (PI) System:**
  - This is a reliability tool used to process and provide visualization of complex real-time power system information in a user-friendly format for the RC operator to process and analyze. The tool provides real-time trending of power system parameters, which enhances situational awareness.

- **Dispatcher Load Flow (DLF) and Contingency Analysis (CA) Study Tools:**
  - These applications are used by the RC operator to manually run load flow and Contingency analysis studies. The Real-time base case solution from SE can be
loaded into these applications, to be used as a starting point to run offline analysis of any scenario the operator wants to study.

9.5.1. RC WEST maintains control standards for its monitoring and analysis tools, including approvals for planned maintenance. RC WEST has procedures in place to mitigate the effects of analysis tool outages. RC WEST ensures that SOL and IROL monitoring continues, even if the main monitoring system is unavailable. RC WEST has backup facilities that shall be used if the main monitoring system is unavailable.

10. Staffing

10.1. Staff Adequately Trained and NERC Reliability Coordinator Certified Personnel – The 24 x 7 RC WEST team consists of:

- Lead Reliability Coordinator,
- Reliability Coordinators, and
- Operations Engineers.

All personnel in these positions possess the NERC Reliability Coordinator certification.

10.2. Compliance - RC WEST has continuous access to staff who are directly responsible for complying with NERC and WECC Standards.

10.3. Comprehensive Understanding - RC WEST operating personnel have an extensive understanding of the BES system within the RC WEST Area, operating practices, operating procedures, operating guides, restoration priorities, restoration objectives, outage plans, equipment capabilities and operational restrictions.

10.4. Priority - RC WEST operating personnel place particular attention on SOLs and IROLs and intertie facility limits. RC WEST ensures that protocols are in place allowing RC WEST operating personnel to have the best available information at all times.

10.5. Continuous Training - RC WEST's RCs are continuously trained on an ongoing basis to perform their duties, and CAISO Operational Readiness Group uses the “Vision Learning Station” application and NERC System Operator Certification and Continuing Education Database (SOCCED) to track the status of each Reliability Coordinator’s training progress, certification and desk qualifications. RC WEST’s are expected to regularly participate and take an active role in regional reliability training.
11. **APPENDIX A – California ISO Governing Documents**


12. **APPENDIX B – Agreements with External Entities**

12.1. Peak Reliability

12.2. British Columbia Hydro Authority (BCHA)

12.3. Alberta Electric System Operator (AESO)

12.4. Southwest Power Pool (SPP)
13. APPENDIX C – CAISO-RC West Reliability Area Map

13.1 CAISO - RC West

CAISO - RC WEST Reliability Map for November 1st, 2019 (non RC West area shows transition from Peak to SPP on 12/3/2019)


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## RC West Coordination Plan

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Introduction

The North American Electric Reliability Corporation (NERC) requires every Region, sub-region, or interregional coordinating group to establish a Reliability Coordinator to provide the reliability assessment and emergency operations coordination for the Balancing Authorities and Transmission Operators within the Regions and across the Regional boundaries.

California ISO Reliability Coordinator (CAISO RCRC WEST) serves as the reliability coordinator (RC) for its Balancing Authority (BA) customers and the Transmission Operating (TOP) customers in their respective BA Areas. The CAISO RCRC WEST functions associated with the reliability of the Bulk Electric System (BES) include:

- Review and approval of planned facility, transmission line outages and generation outages based upon current and projected system conditions,
- Monitoring facilities within its Reliability Coordination Area and neighboring Reliability Coordination areas to identify any System Operating Limit (SOL) exceedances and to determine any Interconnection Reliability Operating Limit (IROL) exceedances within its Reliability coordination area, and
- Issuing Operating Instructions to ensure reliability of the BES is maintained.

CAISO RCRC WEST procedures and policies are consistent with NERC and WECC Regional Reliability Organization (RRO) Standards.

1. Responsibilities – Authorization

1.1. Authority to Act - CAISO RCRC WEST is responsible for the reliable operation of the BES within its Reliability Coordination Area, in accordance with NERC Standards and Regional policies and standards. CAISO RCRC WEST’s authority to act is derived from a set of agreements that all CAISO RCRC WEST members have executed (See Appendices A and C).

1.2. Decision Making Authority - CAISO RCRC WEST has clear decision-making authority to act and to direct or instruct members within its Reliability Coordination Area to take action to preserve the integrity and reliability of the BES. CAISO RCRC WEST’s responsibilities and authorities, as well as its members’ responsibilities, are clearly defined in the governing documents.

1.3. Wide Area view of its Reliability Coordination Area - CAISO RCRC WEST has a Wide Area view of its Reliability Coordination Area and neighboring areas that have an impact on CAISO RCRC WEST’s area. The CAISO RCRC WEST has the operating tools, processes and procedures (including the authority) to prevent or mitigate emergency operating situations in both next-day analysis and during real-time conditions, per the NERC
1.4. Independence - CAISO-RCRC WEST will act in the best interest of insuring reliability for its Reliability Coordination Area and the Western Interconnection, before that of any other entity. This expectation is clearly identified in the governing documents (see Appendix A).

1.5. CAISO-RCRC WEST Operating Instruction Compliance - Per the governing documents (see Appendix A), the participating control centers shall carry out required emergency actions as directed or instructed by the CAISO-RCRC WEST, including the shedding of firm load if required, unless such actions would violate safety, equipment, regulatory, or statutory requirements.

2. Responsibilities – Delegation of Tasks

2.1. CAISO-RCRC WEST has not delegated any Reliability Coordination tasks.

3. Common Tasks for Next-Day and Current-Day Operations

3.1. This section documents how CAISO-RCRC WEST conducts current-day and next-day reliability analysis for its Reliability Coordination Area.

3.2. Determination of Interconnection Reliability Operating Limits (IROLs) – CAISO-RCRC WEST established IROLs in accordance with its SOL methodology.

3.3. During real-time operations, the CAISO-RCRC WEST continuously ensures that the system is resilient and not in danger of cascade failure due to Thermal Cascading (monitored through Real Time Contingency Analysis [RTCA]), Voltage instability (monitored through Voltage Stability Analysis [VSA]) and Dynamic Transient Instability (monitored through Real-Time Dynamic Stability Assessment [RT-DSA]).

3.4. CAISO-RCRC WEST monitors and acts to prevent the likelihood of a SOL or IROL exceedance in its own area or other areas of the Interconnection, and coordinates with impacted Reliability Coordinators when there is a difference in limits. CAISO-RCRC WEST, through the agreements with other Reliability Coordinator neighbors, will coordinate operations to prevent the likelihood of a SOL or IROL in another area. The scope of these agreements includes data exchange and Outage Coordination. (See Appendix B.)

3.5. BA and TOP customer control centers in the CAISO-RCRC WEST Area must follow Operating Instructions provided by CAISO-RCRC WEST. NERC Standards are followed to prevent the likelihood that a disturbance, action, or non-action in its Reliability Coordination Area will result in a SOL or IROL exceedance in its own area or other areas of the Interconnection. When there is a difference in derived limits between RCs, the CAISO-RCRC WEST utilizes the most conservative limit until the difference is resolved.
3.6. Operate under known and studied conditions and reposition without delay and within no longer than 30 minutes following Contingency events or operational situations that require such action – The CAISO RCRC WEST will perform real-time analysis at least once every 30 minutes. Under normal circumstances, the CAISO RCRC WEST will perform real-time analysis after every 5 minute RTCA and VSA run, and after every 15 Minute RT-DSA run. This provides assurance that entities within its Reliability Coordination Area always operate under known and studied conditions and that they return their systems to a secure operating state following Contingency events, within approved timelines. CAISO RCRC WEST also ensures that entities within its Reliability Coordination Area operate the system to be within all IROLs following Contingencies, within 30 minutes.

3.7. On a daily basis, CAISO RCRC WEST conducts Operations Planning Analysis, factoring in planned outages, forecasted loads, generation commitment, and expected net interchange. The analyses include Contingency analysis and voltage stability analysis on key interfaces. These analyses model each operating hour of the day, and include assessment of anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations.

3.8. Results and mitigation are documented in the Day Ahead Reliability Analysis (DARA) report and made available for review, to CAISO RCRC WEST staff and entities within the CAISO RCRC WEST Reliability Coordinator Area and neighboring Reliability Coordinators. Mitigation plans are formed as needed for potential SOL and IROL exceedance determined in the DARA.

3.9. In real-time, CAISO RCRC WEST relies on its telemetry and real-time analysis tools to monitor the real-time system conditions to identify potential IROL and SOL exceedance. CAISO RCRC WEST’s operational philosophy is to monitor and initiate operating plans for all SOL exceedances identified through Real Time Assessment, which include assessment of existing (pre-Contingency) and potential (post-Contingency) operating conditions. CAISO RCRC WEST communicates about IROLs within its RC Area and provides updates as needed via reports, morning conference calls, and in real-time, via voice and messaging.

3.10. CAISO RCRC WEST process for issuing Operating Instructions – CAISO RCRC WEST uses a number of communication tools for issuing/receiving of Operating Instructions. The primary communication means is the CAISO RCRC WEST Turret Phone system, which is a dedicated telephone-based system. The CAISO RCRC WEST will also employ a “Grid Messaging System” that sends instructions/message(s) to all control centers simultaneously, and confirms response. CAISO RCRC WEST communicates Operating Instructions in a clear, concise and definitive manner. When appropriate, three-part communication will be required to ensure the communications are correctly received and understood.

4. Next Day Operations

4.1. This section documents how CAISO RCRC WEST conducts Operational Planning Analysis for its Reliability Coordination Area.
4.2. Reliability Analysis and System Studies – **CAISO.RCRC WEST** conducts Operational Planning Analysis for its Area to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations, and to ensure that the BES can be operated reliably in normal and post-Contingency conditions.

4.3. On a daily basis, **CAISO.RCRC WEST** conducts Operational Planning Analysis, utilizing known outages, forecasted loads, generation commitment and dispatch, and expected net interchange, employing the study capability in the **CAISORC WEST** Network Applications. Base case flows on all monitored facilities are compared against the normal continuous rating. Post-Contingency flows for all monitored facilities are compared against their Emergency rating for all Contingencies. Voltage stability analysis is conducted on key critical interfaces to determine stability limit.

4.4. **CAISO.RCRC WEST** coordinates mitigation plans as needed for potential SOL exceedance determined in the Operational Planning Analysis. Mitigation can include additional generation commitment, system reconfiguration, generation re-dispatch, outage postponement or other local flow mitigation procedures.

4.5. Information Sharing – BAs and TOPs in the **CAISO.RCRC WEST** Area and neighboring Reliability Coordinator areas provide **CAISO.RCRC WEST** with all information required for system studies, such as critical facility status, load, generation, Contingency Reserve projections and known interchange transactions.

4.6. The entities in the **CAISO.RCRC WEST** Area provide expected generation and transmission facility status to the **CAISORC WEST** outage scheduling application, including forecasted loads, operating reserves, and known interchange transactions. **CAISO.RCRC WEST** provides this information through a secure network to applicable members.

4.7. Sharing of Study Results - **CAISO.RCRC WEST** makes available the results of its system studies with the entities within its Reliability Coordination Area and/or with other Reliability Coordinators. **CAISO.RCRC WEST** intends to make study results available for the next day by no later than 16:00 Pacific Prevailing time, unless unforeseen circumstances prevent this.

4.8. Day Ahead Reliability Analysis Report (DARA) - Made available to **CAISO.RCRC WEST** and neighboring Reliability Coordinators. **CAISO.RCRC WEST** holds daily conference calls as necessary, with participating members and others as part of this process.

5. Current-Day Operations

5.1. This section documents how **CAISO.RCRC WEST** conducts Real-Time reliability analysis for its Reliability Coordination Area.

5.2. **CAISO.RCRC WEST** uses a suite of real-time network analysis tools to continuously monitor all BES facilities within the **CAISO.RCRC WEST** Area and adjacent areas, including sub-transmission information as needed, to ensure that **CAISO.RCRC WEST** is able to proactively maintain system reliability. **CAISO.RCRC WEST** makes every effort to prevent...
### 5.3. **CAISO-RCRC WEST** uses both a state estimator and RTCA as the primary tools to monitor facilities. The state estimator model includes all facilities in the WECC BES, as well as facilities in the **CAISO-RCRC WEST** Area. The model also includes extensive representation of neighboring facilities, in order to provide an effective wide-area view, and is updated as required to maintain accurate modelling.

### 5.4. **RTCA** is performed on Contingencies using the state estimator model approximately every five minutes. Contingencies include all **CAISO-RCRC WEST** Area equipment and facilities and also any neighboring RC area equipment that is known to impact the **CAISO-RCRC WEST** area.

### 5.5. In order to continuously monitor its voltage stability limited interfaces, **CAISO-RCRC WEST** uses VSA, a real-time calculation tool. VSA takes a state estimator snapshot and calculates a voltage collapse equivalent flow for the interface, based on current real-time telemetry and topology. A VSA Transfer Limit is established as the limit to prevent a potential post-Contingency voltage instability, and **CAISO-RCRC WEST** operates to maintain flows below the limit.

### 5.6. **CAISO-RCRC WEST** uses SCADA alarming to warn of any actual low or high voltages, or facilities loaded beyond their normal or emergency limits.

### 5.7. In addition to the above-mentioned applications, **CAISO-RCRC WEST** uses dynamically updated transmission overview displays to maintain a wide area view. All transmission facilities 220 kV and above are depicted on the overview with flows (MW and MVAR), indication of facilities out of service, high and low voltage warning and alarming. For more detailed monitoring, **CAISO-RCRC WEST** uses bus level one-line diagrams for station level monitoring and information. The one-line diagrams are populated with the real-time telemetered information, as well as the state-estimated solution.

### 5.8. **CAISO-RCRC WEST** notifies neighboring Reliability Coordinators of operational concerns (e.g. declining voltages, excessive reactive flows, or IROL exceedance) that it identifies within the neighboring Reliability Coordination Area, via direct phone calls, conference calls, NERC hotline calls, and/or RCIS messages. **CAISO-RCRC WEST** has joint operating agreements with neighboring Reliability Coordinators (listed in Appendix B) to provide emergency assistance during declared emergencies.

### 5.9. **CAISO-RCRC WEST** uses State Estimator, RTCA, SCADA alarming, transmission and summary displays to maintain awareness of the status of all current critical facilities whose failure, degradation or disconnection could result in an SOL or IROL exceedance within its Reliability Coordination Area. These same displays and tools keep **CAISO-RCRC WEST** informed of the status of any facilities that may be required to assist Reliability Coordination Area restoration objectives.

### 5.10. **CAISO-RCRC WEST** is continuously aware of conditions within its Reliability Coordination Area, and includes real-time information in its reliability assessments, via automatic updates.
to the state estimator, VSA, and transmission displays. CAISO RCRC WEST monitors its Reliability Coordination Area parameters, including the following:

5.10.1. Current status of BES elements (transmission or generation including critical auxiliaries) such as:

- Automatic Voltage Regulators,
- Remedial Action Schemes (RAS) and
- System loading (monitored by state estimator, RTCA, SCADA Alarming and transmission displays).

CAISO RCRC WEST members are required to report to CAISO RCRC WEST any status changes to RAS or when Automatic Voltage Regulators are not in service.

5.10.2. Current pre-Contingency element conditions (voltage, thermal, or stability) – are monitored by state estimator, SCADA Alarming, RTCA transmission and summary displays.

5.10.3. Current post-Contingency element conditions (voltage, thermal, or stability) – are monitored by RTCA, VSA, DSA and transmission displays.

5.11. CAISO RCRC WEST monitors the availability and deployment of reactive reserves, by monitoring post-Contingent steady state voltages. Reactive Reserve inquiries are made as needed with applicable parties when reactive reserves in real-time appear inadequate or lower than expected.

5.12. Capacity and energy conditions for all CAISO RCRC WEST participants are determined in Day Ahead (DA) and monitored in real-time, in accordance with CAISO RCRC WEST Reliability Processes.

5.13. The CAISO RCRC WEST monitors current BA ACEs and System Frequency trends. This information is used to ensure that a participating BA’s failure to adhere to NERC BAAL Control Standards is not contributing to reliability-related issues. This includes IROL/SOL exceedances or capacity-related issues. If failure to conform to BAAL standards is contributing to an IROL exceedance, the CAISO RCRC WEST will order the use of all resources, including firm load shedding, to relieve the exceedance.

5.14. Planned transmission or generation outages are reported to CAISO RCRC WEST via the Outage Management System (OMS) or other outage reporting applications as agreed to with participants. This outage information, once approved and implemented, automatically or manually updates the Full Network model.

5.15. State estimator, RTCA, SCADA Alarming, and transmission displays monitor Contingency Events. Member control centers report Contingency Events on non-monitored facilities, if needed, to CAISO RCRC WEST.

5.16. CAISO RCRC WEST monitors BES parameters that may have significant impacts upon its Reliability Coordination Area and neighboring Reliability Coordination areas with respect to:
5.16.1. **CAISO-RCRC WEST** monitors all BES facilities within its RC area for current and projected loadings. If reliability impacts are expected or are occurring, the **CAISO-RCRC WEST** may utilize all available resources, up to and including load shedding, to address a potential or actual IROL exceedance. The **CAISO-RCRC WEST** has EMS displays, which allow RC operators to watch and monitor all IROL limits.

5.16.2. **CAISO-RCRC WEST** monitors participating BA’s and Reserve Sharing Groups’ (RSG) Contingency Reserve Actual (CRA) versus their Contingency Reserve Obligation (CRO) to ensure the necessary amounts of Operating Reserves are available as required to meet NERC BAL and EOP Standards. If needed, the **CAISO-RCRC WEST** will undertake Energy Emergency Alert (EEA) procedures or assist with obtaining additional reserves from neighbors.

5.16.3. **CAISO-RCRC WEST** identifies the cause of potential or actual SOL or IROL exceedance via analysis of state estimator results, RTCA results, VSA results, DSA results, SCADA Alarming of outages, transmission displays of changes, and Interchange Transaction impacts. **CAISO-RCRC WEST** will direct or instruct actions including transmission reconfiguration, generation re-dispatch, or emergency procedures to relieve the potential or actual IROL exceedance without delay, and in no longer than 30 minutes. **CAISO-RCRC WEST** is authorized to direct utilization of all resources, including load shedding, to address a potential or actual IROL exceedance.

5.17. **CAISO-RCRC WEST** communicates Geo-Magnetic Disturbance forecast information to participating BAs and TOPs via the **CAISO-RCRC WEST** Messaging tool. **CAISO-RCRC WEST** will assist in development of any required response plan and may move to conservative operating mode to mitigate impacts as needed.

5.18. **CAISO-RCRC WEST** initiates NERC Hotline discussions, to assist in the assessment of reliability of the Regions and the overall interconnected system, and coordinates actions in anticipated or actual emergency situations. **CAISO-RCRC WEST** will disseminate this information via the **CAISO-RCRC WEST** Messaging tool or by individual phone calls.

5.19. **CAISO-RCRC WEST** coordinates, on an as-needed basis, with other Reliability Coordinators and member BAs and TOPs on the development and implementation of action plans to mitigate potential or actual SOL, IROL, BAAL or DCS/BCE exceedance.

5.20. The participating BAs and TOPs within the **CAISO-RCRC WEST** Reliability Area inform **CAISO-RCRC WEST** of all changes in status of RAS, including any degradation or potential failure to operate as expected. **CAISO-RCRC WEST** factors these RAS changes into its reliability analyses and updates its Contingency definitions as appropriate.

5.21. **CAISO-RCRC WEST** confirms reliability assessment conclusions by analyzing results of state estimator/RTCA and discussions with participating BAs and TOPs and neighboring Reliability Coordinators. **CAISO-RCRC WEST** identifies options to mitigate potential or actual SOL or IROL exceedance by examining existing operating procedures, system knowledge, and power flow analysis to identify and implement only those actions necessary to act in the best interests of the interconnection.
6. Emergency Operations

6.1. **CAISO-RCRC WEST** applies operating procedures, RC0310 - Mitigating SOL and IROL Exceedances and RC00410 - System Emergencies (See appendix D), to direct or instruct its TOPs to return the transmission system to within SOL or IROL limits as soon as possible, but no longer than within 30 minutes, to prevent a single or credible multiple Contingency from resulting in instability, uncontrolled separation, or Cascading Outages that adversely impact the reliability of the BES. These actions may include: reconfiguration, re-dispatch, load transfer, schedule curtailment, controllable device operation or load shedding. Load shedding will be considered a last resort to mitigate reliability issues that occur in real-time.

6.2. **CAISO-RCRC WEST** will use RC0310 - Mitigating SOL and IROL Exceedances and/or RC0410 - System Emergencies (See appendix D) when it determines that IROL exceedances are imminent. **CAISO-RCRC WEST** procedures document the processes that **CAISO-RCRC WEST** follows when directing or instructing BAs and TOPs in the actions to be taken to mitigate the IROL exceedance to return the system to a reliable state. **CAISO-RCRC WEST** coordinates its emergency procedures with other Reliability Coordinators, per Appendix B.

6.3. **CAISO-RCRC WEST** directs or instructs BAs and TOPs to take actions in the event the loading of transmission facilities progresses to, or is projected to progress to, a SOL or IROL exceedance. Corrective actions may include: reconfiguration, re-dispatch and/or load shedding to prevent or relieve SOL or IROL exceedance. **CAISO-RCRC WEST** will not rely on, nor wait for, the Qualified Transfer Path Unscheduled Flow (USF) procedure to relieve IROL exceedance. **CAISO-RCRC WEST** will assist with coordination of the USF procedure, if doing so will provide additional relief. **CAISO-RCRC WEST** will adhere to the USF procedure instructions, including curtailing transactions.

6.4. **CAISO-RCRC WEST** utilizes RC0410 - System Emergencies (See appendix D) to mitigate an Energy Emergency within its Reliability Coordination Area. **CAISO-RCRC WEST** will provide assistance to other Reliability Coordinators, per its respective joint operating agreement listed in Appendix B.

6.5. **CAISO-RCRC WEST** utilizes RC0410 - System Emergencies (See appendix D) when it, or a BA or TOP within its Reliability Coordination Area is experiencing a potential or actual Energy Emergency. **CAISO-RCRC WEST** Emergency Operations document the processes and procedures that **CAISO-RCRC WEST** uses to mitigate the emergency condition, including a request for emergency assistance if required.

6.6. **CAISO-RCRC WEST** will coordinate drills and simulations on a regular basis to reinforce competencies required for implementation of Emergency procedures.

7. System Restoration
7.1. Knowledge of CAISO RCRC WEST Area TOP Restoration Plans – CAISO RCRC WEST is aware of each TOP’s System Restoration Plan and has a written copy of each plan. During system restoration, CAISO RCRC WEST monitors restoration progress and acts to coordinate any needed assistance. CAISO RCRC WEST will coordinate the restoration activities, depending on system conditions.

7.2. System Restoration Plan – The CAISO RCRC WEST Restoration protocols are contained in the RC System Restoration Plan. Following a Disturbance in which one or more areas within the CAISO RCRC WEST Area become isolated or blacked out, the CAISO RCRC WEST System Operators will implement the CAISO RCRC WEST Restoration Plan. The scope of the CAISO RCRC WEST’s Restoration Plan ends when all of the TOPs in the CAISO RCRC WEST Area are interconnected, each TOP has transferred authority back to its respective BA(s), the CAISO RCRC WEST Area is interconnected to its neighboring RC Areas and normal operations can be resumed. This Restoration Plan is drilled at least annually or more frequently, as needed.

7.3. Dissemination of Information - CAISO RCRC WEST serves as the primary contact for disseminating information regarding Restoration to neighboring Reliability Coordinators and members not immediately involved in Restoration.

7.4. Restoration - CAISO RCRC WEST approves, communicates and coordinates the re-synchronizing of major system islands or synchronizing points so as not to cause a burden on member or adjacent Reliability Coordination Areas.

8. Coordination Agreements and Data Sharing

8.1. Coordination Agreements: See Appendix B

8.2. Data Sharing - CAISO RCRC WEST determines the data requirements to support its Reliability Coordination tasks and requests such data from members or adjacent Reliability Coordinators. CAISO RCRC WEST provides for data exchange with participating BAs and TOPs and adjacent Reliability Coordinators via a secure network. CAISO RCRC WEST members provide data to CAISO RCRC WEST via mutually agreeable transfer methods identified in the CAISO RCRC WEST’s IRO-010 Data Specification. CAISO RCRC WEST provides data to entities outside CAISO RCRC WEST via direct links and mutually agreeable transfer methods identified in IRO-010 Data Specifications.

9. Facility

9.1. Business Continuity - CAISO RCRC WEST performs the Reliability Coordinator function at the California ISO Headquarters in Folsom, CA, along with the CAISO control center in Lincoln, CA. The Folsom and Lincoln control centers have the necessary voice and data communication links to appropriate entities within CAISO RCRC WEST Reliability Area to
perform their responsibilities. These facilities are staffed 24x7, and are available to act in addressing a real-time emergency condition.

9.2. Adequate Communication Links - CAISO.RCRC WEST maintains satellite phones, cellular phones, and redundant, diversely-routed telecommunications circuits. There is also a video link between the Folsom and Lincoln Control Rooms.

9.3. Multi-directional Capabilities – CAISO.RCRC WEST has multi-directional communications capabilities with its members and neighboring Reliability Coordinators, to meet reliability needs of the Interconnection, for both voice and data exchange.

9.4. Real-time Monitoring – CAISO.RCRC WEST has detailed capability for real-time monitoring of its Reliability Coordination Area and Reliability Coordinators adjacent to the CAISO.RCRC WEST Reliability Coordination Area, to ensure that potential or actual SOL or IROL exceedance is identified. CAISO.RCRC WEST monitors BES elements (generators, transmission lines, buses, transformers, breakers, etc.) that could result in SOL or IROL exceedance within its Reliability Coordination Area. CAISO.RCRC WEST monitors both real and reactive power system flows, operating reserves, and the status of the Bulk Power System elements that are, or could be, critical to SOLs and IROLs and system restoration requirements within its Reliability Coordination Area.

9.5. Study and Analysis Tools - CAISO.RCRC WEST has adequate analysis tools, including state estimation, pre-and post-Contingency analysis capabilities (thermal, stability, and voltage), and wide-area overview displays. CAISO.RCRC WEST has detailed monitoring capability of the CAISO.RCRC WEST Reliability Area and sufficient monitoring capability of the surrounding Reliability Areas to ensure potential reliability issues are identified. CAISO.RCRC WEST continuously monitors key transmission facilities in its area in conjunction with the Members’ monitoring of local facilities and issues.

The systems CAISO.RCRC WEST uses include:

- Energy Management System (EMS)/Supervisory Control and Data Acquisition (SCADA) System:
  - EMS provides the RC operator with real-time monitoring and visibility of the status of BES transmission and generation facilities, RASs, non-BES facilities that impact the BES, and other critical real-time parameters for the reliable operation of the BES. The EMS system also provides alarming of critical events that affect the reliability of the BES.
- State Estimator (SE):
  - This is an application that performs numerical analysis of the real-time network model and data to determine the system’s current condition. The SE can typically identify bad analog telemetry, estimate non-telemetered flows and voltages and determine real time operating limit exceedances. The SE runs every 5 minutes, and provides a base-case solution used by RTCA and VSA applications.
- Real-time Contingency Analysis (RTCA):
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<th>V2 Final Draft</th>
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**RC West California ISO Reliability Coordination Plan**

- This is a primary Real-time Assessment application that runs every 5 minutes and automatically performs analyses of all identified single and credible multiple Contingencies that affect the RC Area. The RC operator uses the results to identify potential post-Contingency thermal or voltage exceedances on the system and to proactively develop mitigation plans to ensure reliability.

- **Real-time Voltage-Stability Analysis (VSA):**
  - This application runs every 5 minutes and performs voltage-stability analyses of predetermined stability limitations on the system to determine voltage-stability limits and margins for those interfaces.

- **Real-time Dynamic Stability Analysis (RT-DSA):**
  - This application runs every 15 minutes and performs transient stability analyses of predetermined stability limitations on the system to identify transient-stability limits and margins for those interfaces.

- **Plant Information (PI) System:**
  - This is a reliability tool used to process and provide visualization of complex real-time power system information in a user-friendly format for the RC operator to process and analyze. The tool provides real-time trending of power system parameters, which enhances situational awareness.

- **Dispatcher Load Flow (DLF) and Contingency Analysis (CA) Study Tools:**
  - These applications are used by the RC operator to manually run load flow and Contingency analysis studies. The Real-time base case solution from SE can be loaded into these applications, to be used as a starting point to run offline analysis of any scenario the operator wants to study.

9.5.1. **CAISO RCRC WEST** maintains control standards for its monitoring and analysis tools, including approvals for planned maintenance. **CAISO RCRC WEST** has procedures in place to mitigate the effects of analysis tool outages. **CAISO RCRC WEST** ensures that SOL and IROL monitoring continues, even if the main monitoring system is unavailable. **CAISO RCRC WEST** has backup facilities that shall be used if the main monitoring system is unavailable.

**10. Staffing**

10.1. **Staff Adequately Trained and NERC Reliability Coordinator Certified Personnel – The 24 x 7 CAISO RCRC WEST team consists of:**

- Lead Reliability Coordinator,
- Reliability Coordinators, and
- Operations Engineers.
All personnel in these positions possess the NERC Reliability Coordinator certification.

10.2. Compliance - CAISO RCRC WEST has continuous access to staff who are directly responsible for complying with NERC and WECC Standards.

10.3. Comprehensive Understanding - CAISO RCRC WEST operating personnel have an extensive understanding of the BES system within the CAISO RCRC WEST Area, operating practices, operating procedures, operating guides, restoration priorities, restoration objectives, outage plans, equipment capabilities and operational restrictions.

10.4. Priority - CAISO RCRC WEST operating personnel place particular attention on SOLs and IROLs and intertie facility limits. CAISO RCRC WEST ensures that protocols are in place allowing CAISO RCRC WEST operating personnel to have the best available information at all times.

10.5. Continuous Training - CAISO RCRC WEST’s RCs are continuously trained on an ongoing basis to perform their duties, and CAISO Operational Readiness Group uses the “Vision Learning Station” application and NERC System Operator Certification and Continuing Education Database (SOCCED) to track the status of each Reliability Coordinator’s training progress, certification and desk qualifications. CAISO RCRC WESTs are expected to regularly participate and take an active role in regional reliability training.
11. **APPENDIX A – California ISO Governing Documents**


12. **APPENDIX B – Agreements with External Entities**

12.1. Peak Reliability

12.2. British Columbia Hydro Authority (BCHA)

12.3. Alberta Electric System Operator (AESO)

12.4. Southwest Power Pool (SPP)
13. APPENDIX C — CAISO-RC West California ISO Reliability Area Map

13.1 CAISO - RC West

CAISO-RC, California ISO Reliability Plan for November 1st to July 1, 2019 (non-RC West area shows transition from Peak to SPP on 12/3/2019)
### Reliability Coordinator Procedure

**Version No.** V2 **Final Draft**

**Effective Date** 7/1/2019

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13.2 List of Participating Balancing Authorities and Transmission Operators for **November 1st** 2019.
| Los Angeles Department of Water and Power (LADWP) - City of Los Angeles, Department of Water and Power | 1-Jul | X | X | LADWP | LDWP |
|MATL LLC (Montana Alberta Tie Line LLP) | 1-Nov | . | X | NWMT | MATL |
|Modesto Irrigation District (MID) | 1-Jul | . | X | BANC | MID |
|National Nuclear Security Administration – Los Alamos (NNSAL) | 1-Nov | . | X | PNM | MIDT |
|NaturEner Power Watch, LLC | 1-Nov | X | X | GWA | GWA |
|NaturEner Wind Watch, LLC | 1-Nov | X | X | WWA | WWA |
|Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy | 1-Nov | X | X | NVE | NEVP |
|NorthWestern Corporation d/b/a NorthWestern Energy | 1-Nov | X | X | NWMT | NWMT |
|Pacific Gas and Electric Company (PGAE) | 1-Jul | . | X | CAISO | PCG |
|Pacificorp | 1-Nov | X | X | PAC | PAC |
|Portland General Electric Company | 1-Nov | X | X | PGE | PGE |
|Public Service Company of New Mexico (PNM) | 1-Nov | X | X | PNM | PNM |
|Public Utility District #1 of Chelan County, Washington | 1-Nov | X | X | Chelan | CHPD |
|Public Utility District No. 1 of Douglas County | 1-Nov | X | X | Douglas | DOPD |
|Public Utility District No. 1 of Snohomish County | 1-Nov | . | X | BPA | SNPD |
|Public Utility District No. 2 of Grant County, Washington | 1-Nov | X | X | Grant | GPUD |
|Puget Sound Energy | 1-Nov | X | X | Puget | PSEI |
|Sacramento Municipal Utility District (SMUD) | 1-Jul | . | X | BANC | SMUD |
|Salt River Project Agricultural Improvement and Power District (SRP) | 1-Nov | X | X | SRP | SRP |
|San Diego Gas & Electric Company (SDGE) | 1-Jul | . | X | CAISO | SDGE |
|Southern California Edison Company (SCE) | 1-Jul | . | X | CAISO | SCE |
|Trans Bay Cable LLC | 1-Jul | . | X | CAISO | TBC |
|Tri-State Generation and Transmission Association, Inc. | 1-Nov | . | X | PNM | TSIGT |
|Turlock Irrigation District | 1-Jul | X | X | TID | TIDC |
|U.S. Department of Energy acting by and through the Bonneville Power Administration (BPA) | 1-Nov | X | X | BPA | BPAT |
|Valley Electric Association, Inc. | 1-Jul | . | X | CAISO | VEA |
|Western Area Power Administration - Sierra Nevada Region | 1-Jul | . | X | BANC | WSN |
|NaturEner USA, LLC | 1-Apr | X | X | PPWR | PPWR |
|Gridforce Energy Management, LLC | 1-Nov | X | . | . | GRID |
## Coordination Plan Distribution Restriction:

- **None**
- **TBD**

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*Not a NERC registered entity
14. **APPENDIX D – California ISO Reliability Coordination Procedures**

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Situational Awareness for FERC, NERC, and the Regional Entities (SAFNR)v3
Building a Common Relevant Operational Picture

Mike Legatt, Ph.D., CPT
CEO and Founder

NERC Operating Reliability Subcommittee
September 4, 2019
Core Philosophies:

The most important components on the grid are the human beings in control rooms and in the field.

“All critical infrastructures are perfectly aligned to get the results they get.”
Overview

• **SAFNRv3 Update.** ICCP connectivity, model updating, GridEx V

• **Situational Awareness.** Ability to collaborate increasingly important in high-stakes situations

• **Human Factors Design to Facilitate:** Reducing switch-tasking and streamlining collaborations

• **Common Relevant Operational Picture (CROP)** - Being able to share common views reduces friction and error risks. During events, ability to collaborate a critical function
SAFNRv3 Update

- ResilientGrid selected by NERC as the vendor to deliver SAFNRv3
- Had piloted with NERC, FERC, and E-ISAC in late 2017
- As part of this pilot, supported NERC and E-ISAC operators during GridEx IV
- As part of a continuous improvement methodology, ResilientGrid continues to work with NERC and E-ISAC operations to look at improving a “single pane of glass” view for real-time operations
- For example, streamlining OE-417 & EOP-004 processing
SAFNRv3 Update

• Initial build-out uses SAFNRv2 model ported to ResilientGrid OS
• Hosted in a secured data center in Austin, BCP site in Atlanta
• EIDSN connectivity online early September, WIDSN late September
• ResilientGrid to work with RCs, bringing ICCP connectivity online
SAFNRv3 Update

- SAFNR system online for testing with RCs anticipated in November.
- Upon successful go-live, SAFNRv2 will be discontinued, and ResilientGrid will move to a continuous improvement cycle with the tool.
- SAFNRv3 is a platform to support shared situational awareness between NERC, FERC, E-ISAC, the REs and the RCs.
- SAFNR is not designed to replace any other tool currently in use in those entities.
SAFNRv3 Update

• Weather radar map overlays
• Weather alert overlays
• Weather station data and contours
• FNET frequency deviations and oscillations
• Wildfires
• NERC PI historical data
Situational Awareness

Scanning

Focus

THREAT!!!!
Situational Awareness?
What is Situational Awareness?

• **Situational Awareness** requires people to **focus** and **scan** all the time – which the brain clearly can’t do!

• **Information Processing** – most systems force information processing onto the operator

• **Inattentional Blindness** – while switch-tasking, people miss changes in system state

• **Out of the Loop Syndrome** – If our automation isn’t designed to keep the operator involved, the operator can’t maintain situational awareness.
Data vs. Information
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<th>Section</th>
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<th>Status</th>
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Manage Cognitive Load

- Workflow analysis, specific and holistic
- Analysis of short-term memory loading (7 ± 2 chunks; Miller, 1956)
- Recognition that humans make 3-7 mistakes per hour, 11-15 under stress (Muschara, 2014)
- Recognition of lower cognitive resource availability in emergencies
- Analysis against predictable failure modalities in emergencies

A Dynamic Model of Stress and Attention, from Hancock & Warm (1989)
Build for Holistic Success and Keep Scanning
Thank You!!!

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resilientgrid.com/ors2019
January 11th Oscillation Event
Follow-up

Tim Fritch, SMS Vice-Chair
ORS Meeting
September 4, 2019
• Eastern Interconnection Oscillation was observed from 08:44:41 UTC (03:44:41 EDT) to 09:02:23 UTC (04:02:23 EDT) on January 11th, 2019

• NERC SMS surveyed industry to better understand the following
  ▪ Awareness of event and mitigations taken
  ▪ Communications between RCs
  ▪ Tools to monitor interconnections for oscillations
  ▪ Improvements on compliance guidelines

• Survey consisted of seven questions and a general comments sections

• Eleven utilities participated in the survey
1. Is your company registered as a TOP? RC? Both TOP and RC?

2. Were your operators aware of the 1/11/2019 Eastern Interconnection oscillation during the event (8:44-9:02 UTC)?

2a. If so, how were your operators made aware of the event?

2b. Did your operators take any action for the event on 1-11-2019?

3a. Does your company feel there is an industry need to develop PMU data sharing requirement for RCs to help address this concern?

3b. Does your company feel there is an industry need to develop a real-time regional oscillation and source detection tool? (i.e. Fnet)

3c. Should NERC SMS work to identify and address gaps in existing NERC reliability standards on RC to RC coordination? (i.e. IRC-014-3)
• Most RCs and TOPs in EI were aware of the event
• Few took action during the event to mitigate oscillations (i.e. removed AGC for units)
• Improve PMU data sharing between utilities to provide better situational awareness and potential source of oscillation
• Provide better guidance on operating plans to RC and TOP on what actions need to be taken
• Existing standards needs to be reviewed to see if language needs to be more descriptive to address these types of events
• Investigate tools that provide interconnection oscillation detection
• Industry agrees more visibility, training, and communication for these type of events is needed

• Reliability standards need to be reviewed for these types of events on communications

• Utilities need better understanding of these types of events on how to identify and respond
Training

- Companies should develop training their operators to help them understand the difference between local oscillations isolated to a plant vs the ‘natural mode’ oscillations that can impact the Interconnection, as well as the associated reliability concerns raised by each.

Communication/Tools/Action

- RC’s need to have the tools necessary to identify when and where an oscillation is occurring
  - Opportunity to promote the ESAMS tool PJM is working on.
- RC’s need to be able to communicate quickly with impacted RCs
  - ORS item to discuss the NERC hotline and how to initiate calls with impacts RCs (West or East only)
- Common understanding that there is an issue and which type – local vs natural mode.
- RC’s need to know what actions to take (identify and shut down the unit causing the oscillation) vs what actions NOT to take to mitigate the issue (taking units off AGC, disabling AVRs, etc.)
  - ORS could develop a guideline/procedure to address this but we need the SMS to help us accurately capture the actions to take and not take.
Questions and Answers
Geomagnetic Disturbances
Operating Procedure and Alert Notification Discussion

Chris Balch, NOAA Space Weather Prediction Center
Mark Olson, Senior Engineer Reliability Assessments
Operating Reliability Subcommittee (ORS)
September 5, 2019
• Reducing risks to the BPS from space weather continues to be an ERO priority
• GMD risk mitigation activities include:
  ▪ Ongoing research with EPRI and other collaborators
  ▪ Implementation of GMD Reliability Standards
  ▪ Implementation of GMD Data Collection (Section 1600)
Importance of GMD Operating Procedures

- Research and planning efforts are focused on future... **GMD Operating Procedures are IN PLACE TODAY:**
  - NERC Alert released in August 2011
  - NERC GMD Task Force (GMDTF) Operating Procedure Templates approved February 2013
  - Reliability Standard EOP-010-1 became effective in U.S. in 2015

- Operating actions can mitigate GMD impacts:
  - Increased situational awareness
  - System posturing
  - Reconfiguration

- NOAA Space Weather Prediction Center (SWPC) and Space Weather Canada provide alerts to operators
SWPC Update
NOAA’s Space Weather Prediction Center

- SWPC Operations Center
  - staffed 24 hours x 7 days

- Synthesis of space weather data and information

- Nation’s official source of space weather alerts, warnings and forecasts
Cause & Effect - Sun to Mantle - I

SOHO C2 data courtesy of the NASA/ESA

Output from WSA-Enlil-Cone model for series of three CME’s observed in August 2011

Conceptual model for solar-wind-magnetosphere interaction

Image of the auroral oval from the Dynamics Explorer 1 Satellite (Louis Frank)

Time varying currents in space induce currents in the Earth and in artificial conductors at the surface - Boteler (2015)

Input: Geomagnetic Field Time Series
March 13-14, 1989 Geomagnetic storm observed at Ottawa (NRCAN)

Output: Geoelectric Field Time Series
Calculated Geoelectric Field with a simple conductivity model

Earth Conductivity:
- frequency dependent filter
- varies with location
- depends on structure below the mud

The induced electric field drives current in conductors on and below the surface of the Earth
Near real-time K-indices are updated promptly as data arrives.

Estimates of K-indices for the current 3-hourly interval are displayed from the available Kp network stations.

Kp is calculated from the network station K’s using the traditional conversion tables.

Alerts are issued when thresholds are crossed, even if that time precedes the end of the three hourly period.

Forecasters use their judgement for borderline cases, and can also flag bad data or inactivate/reactivate stations if appropriate.
Space Wx Products

- Twice per day Discussion and 3 day Forecast
- Geomagnetic Storm Watch
- Geomagnetic Storm Warning
- Geomagnetic Storm Alert
- Maintain Operational Space Weather Observations:
  - GOES satellites
  - DSCVR mission (L1 – ACE replacement)
- Graphical map for Regional Geoelectric Field Estimates
**E-field maps data pipeline - today**

**USGS observatories (8)**
B-field time series

**NRCAN observatories (5)**
B-field time series

**Detrending Algorithm**

**Interpolation Algorithm†**
B-field on 0.5° x 0.5° grid

**E-field calculation:**
2° x 2° grid, 1D conductivities

**E-field experimental products:**
- results in database
- graphical maps (public release Oct ‘17)
- gridded data files (available on request)
- GeoJSON format for dissemination
  (June 15, 2018)

Operational deployment for first version is underway – should be completed by September 30, 2019

† SECS - Amm & Viljanen, 1999; Pulkkinen et al., 2003

**URLs**
[http://services.swpc.noaa.gov/experimental/products/lists/rgeojson.json](http://services.swpc.noaa.gov/experimental/products/lists/rgeojson.json) (for list of geojson files)
Solar Cycle 24

- **Smoothed Monthly Mean International SSN**
- **Monthly Mean International SSN**

Cycle Begins December 2008
August 2019 is month 129
Max SSN = 116.4 for April 2014
Future Efforts
Challenges to Maintaining Proficiency

- Recent solar cycles have been relatively quiet
  - Infrequent strong GMD events \((K_p \geq 7)\) may reduce operator familiarity
- Industry has focused on developing and implementing GMD planning standards
  - GMDTF focus on GIC studies, GMD Vulnerability Assessments, TPL-007
- New Reliability Coordinators (RCs) have been established and RC footprints are changing
NERC staff would like to discuss ORS support for initiatives aimed at maintaining effective GMD Operating Procedures:

- Collaboration with SWPC on operator information and training materials
- Collaboration with GMDTF to develop a panel session on industry operating procedures and best practices
- Consider including guidance for periodic testing of the SWPC-to-Reliability Coordinator notification procedure in the Monitoring Reference Document
- Other suggestions?
Discussion and Next Steps