

 California ISO   RC West	<b>Reliability Coordinator Procedure</b>	<b>Procedure No.</b>	RC0610
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<b>System Operating Limits Methodology for the Operations Horizon</b>		<b>Distribution Restriction: None</b>	

# SYSTEM OPERATING LIMITS METHODOLOGY FOR THE OPERATIONS HORIZON


**Rev. 3.4**

**By**  
**California Independent System Operator**  
**Reliability Coordinator**  
**(RC West)**


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## A. Conventions

When a term from the North American Electric Reliability Corporation (NERC) Glossary of Terms is used in this document, the term will be capitalized. Other capitalized terms are defined in this document and listed in Appendix A.

## B. Introduction and Purpose

This document is the RC West’s System Operating Limit (SOL) Methodology for the Operations Horizon [NERC Standard FAC-011-4 R1]. The document establishes the methodology to be used in the RC West Area for developing SOLs and Interconnection Reliability Operating Limits (IROLs) for use in the Operations Horizon pursuant to NERC Reliability Standards FAC-011-4 and FAC-014-3.

All requirements for establishing SOLs and IROLs are contained in the body of this document. The appendices provide best practices or background information but do not contain additional requirements not identified in the body of this document.

The task of TOPs and the RC is to continually assess and evaluate projected system conditions within the Operations Horizon with the objective of ensuring acceptable system performance in Real-time. These assessments are performed in an iterative fashion, typically beginning as part of seasonal studies, followed by assessments performed as part of the IRO-017-1 Outage Coordination Process, followed by Operational Planning Analyses (OPAs), and concluding with Real-time Assessments (RTAs). Accordingly, these studies use anticipated transmission system configuration, generation dispatch and load levels, which are expected to improve in accuracy through the iterative assessments as Real-time approaches [NERC Standard FAC-011-4 R4.4].

## C. Applicability


This SOL Methodology applies to the following entities within the RC West Area for developing SOLs and IROLs used in the Operations Horizon [NERC Standard FAC-011-4 R1]:

1. TOPs, and
2. RC West.

This SOL Methodology defines Operations Horizon as:

*A rolling 12-month period starting at Real-time (now) through the last hour of the twelfth month into the future.*

The concepts in this SOL Methodology apply to all sub-horizons within the Operations Horizon – seasonal studies, Outage Coordination studies, OPAs, and RTAs.

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## D. SOL versus TTC

WECC paths do not have single uniquely monitored SOL unless the WECC path is associated with an established transient or Voltage Stability Limit.

SOLs are the Facility Ratings, System Voltage Limits, transient Stability Limits, and voltage Stability Limits that are used in the Operations Horizon – any of which can be the most restrictive limit at any point in time, pre- or post-Contingency. A generator producing more than its nameplate rating is not an indicator of SOL exceedance.

Total Transfer Capability (TTC) is the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions. While it is expected that TTCs respect pre- and post-Contingency reliability limitations associated with Facility Ratings, System Voltage Limits, and Stability limits, the determination and communication of TTC is outside the scope of RC West’s SOL Methodology.

Exceeding a TTC value does not constitute an SOL exceedance. However, if a TOP so chooses, the TOP may utilize TTC (and Transfer Capability concepts) as part of an Operating Plan.


## E. The Role of Nomograms

Nomograms are created ahead of time to predict a region that, when operating within it, is expected to provide acceptable pre- and post-Contingency system performance. Nomograms may be used to provide System Operators with helpful guidance as part of an Operating Plan; however, they are not considered to be SOLs unless the nomogram represents a region of Stability (i.e., the nomogram defines a Stability Limit).

## F. Selection of Applicable Contingencies

1. This SOL Methodology defines the following terms as:
  - a. Credibility – the quality of being plausible (believable) and likely (probable).
  - b. Credible Multiple Contingency (MC) – a MC whose Credibility is considered sufficiently high to warrant protecting against.
  - c. Observable System Conditions – known, observable or foreseeable conditions which increase the likelihood of a MC occurring enough to make it a Credible MC. The conditions could be external, such as a brush fire or severe weather (e.g., flooding, icing, tornados), or internal, such as a breaker with a low-gas alarm which poses an elevated risk that the breaker may not operate as anticipated to clear a fault.

**Note:** *Impact to the BES is not an observable system condition.*
  - d. Always Credible MC – a MC that has static Credibility (as a Credible MC) through all phases of the Operations Horizon (seasonal and other special studies, outage coordination assessments, Operational Planning Analyses, and Real-time Assessments). This MC’s Credibility is not a function of Observable System Conditions.

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**Note:** The TOP's list of Always Credible MC's is determined by an internal TOP risk assessment (i.e., likelihood and impact).


- e. Conditionally Credible MC – a MC whose Credibility is a function of Observable System Conditions. Conditionally, Credible MCs are only Credible when the Observable System Conditions are present. When the Observable System Conditions are not present, the MC is not Credible.

**Note:** Conditionally Credible MCs are a function of Observable System Conditions that increase the likelihood of the MC only, not a function of BES impact.

2. The following Contingencies, at a minimum, are applicable to TOP assessments within the Operations Horizon [NERC Standard FAC-011-4 5]:
  - a. Single Contingencies internal to the TOP Area [NERC Standard FAC-011-4 5.1],
  - b. Credible MCs internal to the TOP Area, and [NERC Standard FAC-011-4 5.2],
  - c. Any single Contingencies and Credible MCs external to the TOP Area that are known to impact the TOP Area or system under study, as determined by the TOP or RC. TOPs are responsible for determining the external modeling necessary to support the evaluation of those Contingencies [NERC Standard FAC-011-4 5.2], and
  - d. Any contingencies provided by Planning Coordinators/Transmission Planner according to [NERC Standard FAC-014-3 R7] that are also deemed credible based on the RC SOL methodology for the Operations Horizon [NERC Standard FAC-011-4 5.3].
  
3. The single Contingencies that shall be studied for assessments within the Operations Horizon include the following [NERC Standard FAC-011-4 5.1.1]:
  - a. Loss of any of the following either by single phase to ground or three phase Fault (whichever is more severe) with Normal Clearing, or without a Fault:
    - i. Generator,
    - ii. Transmission circuit,
    - iii. Transformer,
    - iv. Shunt device, or
    - v. Single pole block in a monopolar or bipolar high voltage direct current system.
  
4. The Credible MCs that shall be studied for assessments within the Operations Horizon include the following two types [NERC Standard FAC-011-4 5.2]:<sup>1</sup>
  - a. Always Credible MCs, and
  - b. Conditionally Credible MCs.

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<sup>1</sup> Credible MCs in the Operations Horizon shall be, at a minimum, studied as SLG. Alternatively, a TOP may study Credible MCs as three-phase Faults.

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Note that N-1-1 Contingency types (corresponding to P3 and P6 Contingencies in TPL-001-5.1, Table 1) are not included for consideration as Credible MCs within the Operations Horizon. A specific combination of two overlapping single Contingencies by itself is not an issue of Credibility or non-Credibility. Rather, it is a matter of knowing which combination of overlapping single Contingencies to be prepared for, based on known issues with those specific combinations. Such operational risks are expected to be addressed through Operating Plans as these risks are identified.


Reference Appendix E for more information about how N-1-1 studies may be used to determine IROLs.

### **Requirements for Determining Always Credible MCs**

1. When developing the list of Always Credible MCs for operations, TOPs shall perform an internal risk assessment (i.e., likelihood and impact) to determine the MCs internal to their TOP Area that shall be considered Always Credible for operations based on factors and issues that are unique to their TOP Area. Appendix C contains possible approaches for internal risk assessment.
2. It is the primary responsibility of the TOP in whose TOP Area the MC Facilities reside to determine MC Credibility. However, because the RC is the highest reliability authority in its RC Area, the RC has the authority to determine an MC's Credibility that supersedes a TOP's designation. Should the RC exercise such authority, the RC should perform an evaluation of historical MC performance, and a risk assessment based on the factors and issues driving the RC to supersede the TOP's determination, and the RC shall share this information with impacted TOPs.
3. When an MC terminates in different TOP Areas, the TOPs are expected to collaborate and agree on the MC Credibility.
4. If an impacted TOP challenges or disagrees with a TOP's decision or rationale for a MC's Credibility, or if TOPs cannot agree on the Credibility of the MC that impacts their TOP Area, the TOPs involved are expected to coordinate with the RC to reach a resolution. If agreement/resolution cannot be achieved through collaboration, the RC has the authority to make the final determination of the MC Credibility. In its final determination, the RC is expected to coordinate with the applicable Planning Coordinator(s) (PC(s)) and to consider how the system was planned, built, and is intended to be operated. The RC will document the final resolution.

### **Always Credible MC Communication**

1. TOPs shall review their list of Always Credible MCs annually at a minimum, and document changes to the list of Always Credible MCs. TOPs must use the template posted to RC West's portal titled "Always Credible Multiple Contingencies TEMPLATE.xlsx" to communicate TOP-identified Always Credible MCs. TOPs shall post the populated template for its TOP Area in the "Always Credible MCs" folder in the "SOL Methodology" library in the secure RC West portal. If the TOP does not have any Always Credible MCs, the TOP shall post a "null list" with a note in the spreadsheet indicating that the TOP has not identified any Always Credible MCs for their TOP Area. TOPs shall submit the completed spreadsheet with the filename "Always Credible Multiple Contingencies – TOPxyz.xlsx."

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2. When a TOP posts an updated list to the “Always Credible MCs” folder, the TOP must delete prior versions and fill out the “Revision History” tab in the updated list. Note that prior versions deleted from the folder are available for viewing in the Archive library.
3. Any known changes to the list of Always Credible MCs shall be posted six months<sup>2</sup> before the start of each operating season. Note that the template requires each Always Credible MC to be accompanied by a rationale for its Credibility.

### **Addressing Conditionally Credible MCs**

1. Conditionally Credible MCs are not required to be pre-identified or included along with the list of Always Credible MCs. However, if the TOP pre-identifies any Conditionally Credible MCs and creates a standing Operating Plan for that MC, the TOP shall provide that Operating Plan to the RC for awareness purposes. If such pre-identified Operating Plans impact or involve other TOPs, then the Operating Plan shall be developed in collaboration with the impacted/involved TOPs and communicated to those TOPs.
2. Conditionally Credible MCs become credible when the Observable System Conditions are present. The TOP in whose TOP Area the MC Facilities resides is responsible for determining when a Conditionally Credible MC becomes credible and when it ceases to be credible.
3. When a Conditionally Credible MC becomes credible, the TOP in whose TOP Area the MC Facilities reside must notify the RC and other TOPs known or expected to be impacted by the MC. This notification shall include at a minimum:
  - MC description,
  - MC type,
  - Impacted TOPs,
  - The Observable system Conditions,
  - Projected duration of the MC’s Conditional Credibility, and
  - Any Operating Plans that may be required because of the MC.
4. When a Conditionally Credible MC is no longer credible, the TOP in whose TOP Area the MC Facilities reside must notify the RC and other TOPs identified in item 13 that the MC is no longer credible.
5. The TOP in whose TOP Area the MC Facilities reside must collaborate with the RC and impacted TOPs to create and implement an Operating Plan (or to implement a pre-determined Operating Plan) to address the Conditionally Credible MC. If agreement/resolution cannot be achieved

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<sup>2</sup> Study plans are finalized six months before the start of the operating season in the Recommended Seasonal Operations Planning Coordination Process. However, it is acceptable for changes to the list of Always Credible MCs to be made with less than six months’ notice when the change becomes known less six months ahead of the operating season.

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through collaboration, the RC has the authority to make the final determination of the Operating Plan(s). In its final determination, the RC is expected to coordinate with the impacted TOPs.


6. Impacted TOPs and the RC are expected to include the Conditionally Credible MCs in their respective studies while the Conditionally Credible MC is credible.
7. When Conditionally Credible MCs become credible and the MC impacts multiple TOPs, the RC will collaborate with impacted entities to ensure that the MC is being addressed in a coordinated manner.

### **Requirements for the Treatment of Credible MCs**

1. The RC must include Always Credible MCs in RC assessments (seasonal studies, special studies, outage coordination studies, OPAs, RTAs). The RC must include Conditionally Credible MCs in RC assessments while the MC is credible.
2. TOPs must include their own Always Credible MCs in TOP assessments (seasonal studies, special studies, outage coordination studies, OPAs, RTAs). The TOP must include its own Conditionally Credible MCs in TOP assessments while the MC is credible.
3. If TOP seasonal studies, special studies, outage coordination studies or OPAs fail to verify acceptable system performance for an Always Credible or applicable Conditionally Credible MC, the TOP and all impacted TOPs must collaborate and develop an Operating Plan(s) to provide acceptable performance for the MC. If agreement/resolution cannot be achieved through collaboration, the RC has the authority to make the final determination of the Operating Plan(s). In its final determination, the RC is expected to coordinate with all impacted TOPs. The RC may determine that an IROL needs to be established to address the reliability risk. Reference the IROL Establishment section of this SOL Methodology for more information. Similarly, if TOP RTAs fail to verify acceptable system performance for a credible MC, the TOP must implement an Operating Plan to mitigate the unacceptable system performance for the credible MC.
4. RC West includes credible MCs in RC assessments (both Always Credible MCs and any applicable Conditionally Credible MCs that are communicated to the RC) and evaluates those MCs. RC West applies the Cascading test as described in the section entitled *Instability, Cascading, Uncontrolled Separation and IROLs* when determining potential Cascading.

RC West does not evaluate credible MCs against more stringent performance requirements. If RC West's special studies, Outage Coordination studies or OPAs fail to verify acceptable system performance for a credible MC, an Operating Plan must be developed to provide acceptable performance for the credible MC. Similarly, if RC West's RTAs fail to verify acceptable system performance for a credible MC, an Operating Plan must be implemented to mitigate the unacceptable system performance for the credible MC. RC West does not include non-credible MCs in RC assessments.

5. If an MC is not declared as Always Credible by the TOP in whose TOP Area the MC Facilities reside and is not posted on the RC West portal, then the MC is not required to be honored in the Operations Horizon (seasonal studies, special studies, outage coordination assessments, OPAs,

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RTAs). Note that Conditionally Credible MCs that become credible in the Operations Horizon are addressed separately (See Items 1-7 above).

6. Note that not “all” Contingencies within a TOP Area (single Contingencies or credible MCs) are expected to be included in certain types of analyses. For example, time-domain, PV/QV, and transfer studies are not conducive to analyzing as many Contingencies as can be done in steady-state Contingency analyses performed as part of a power flow. For studies such as time-domain analyses and PV/QV analyses, TOPs and the RC are expected to include those Contingencies that are the most severe to the situation based on experience, engineering judgment and historical analysis.
7. If a TOP determines that a MC in its TOP Area is non-credible, yet a neighboring/impacted TOP desires to include that non-credible MC in its assessments, the neighboring/impacted TOP may do so. However, the neighboring/impacted TOP cannot require other TOPs to address reliability issues related to the non-credible MC and cannot require any other TOP to honor that MC in operations, or in the development or implementation of Operating Plans.
8. The RC shall consider any of the MCs that have been determined credible based on the submission by its PC due to identified instability limits [NERC Standard FAC-011-4 R5.3].

## G. Acceptable System Performance

In the RC West Area, the BES is expected to be operated so that acceptable system performance is achieved in both the pre- and post-Contingency state. This section describes acceptable system performance for the pre- and post-Contingency state [NERC Standard FAC-011-4 R6].


If the TOP or RC analyses are technically accurate yet the results of the studies determining system performance do not agree (i.e., if one TOP’s analysis results differ from another TOP’s analysis results, or if a TOP’s analysis results differ from the RC’s analysis results), then the most limiting analysis is used as a default if the differences cannot be resolved.

It is not the intent of this SOL Methodology to require more stringent BES performance criteria than that stipulated in the prevailing NERC Transmission Planning (TPL) Reliability Standards and WECC TPL criteria; however, this SOL Methodology may prescribe specific performance criteria where the corresponding performance criteria in planning is non-specific.

### 1. Pre-Contingency:

Acceptable system performance for the pre-Contingency state in the Operations Horizon is characterized by the following [NERC Standard FAC-011-4 R6.1]:<sup>5</sup>

- a. Steady state flow through all Facilities shall be within their normal Facility Ratings. Emergency Ratings may be used when System adjustments to return the flow within its Normal Rating could be executed and completed within the specified time duration of those Emergency Ratings (Refer to Figure 1: SOL Performance Summary for Facility Ratings below.) [NERC Standard FAC-011-4 R6.1.1].

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- b. Steady state voltages of all Facilities shall be within their normal System Voltage Limits, and emergency System Voltage Limits may be used when System adjustments to return the voltage within its normal System Voltage Limits could be executed and completed within the specified time duration of those emergency System Voltage Limits [NERC Standard FAC-011-4 R6.1.2].
- c. Predetermined stability limits are not exceeded [NERC Standard FAC-011-4 R6.1.3].
- d. Instability, Cascading, or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur [NERC Standard FAC-011-4 R6.1.4].

2. Post-Contingency:

Acceptable system performance for the post-Contingency state for single Contingencies and Credible MCs in the Operations Horizon is characterized by the following [NERC Standard FAC-011-4 R6.2, R6.3]:<sup>3</sup>


- a. All Facilities<sup>4</sup> shall be within applicable emergency Facility Ratings. Steady state post-Contingency flow through a Facility must not be above the Facility’s highest Emergency Rating. (Refer to Figure 1: SOL Performance Summary for Facility Ratings below.) [NERC Standard FAC-011-4 R6.2.1]
- b. All Facilities shall be within their emergency System Voltage Limits [NERC Standard FAC-011-4 R6.2.2].
- c. All Facilities shall be within their Stability Limits [NERC Standard FAC-011-4 R6.2.3].
- d. Instability, cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur [NERC Standard FAC-011-4 R6.2.4].

For contingencies identified in Section F, planned manual load shedding is acceptable only after all other available System adjustments have been made, provided the Contingency would not result in instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System [NERC Standard FAC-011-4 R6.4]. If the required System adjustments could impact delivery of energy to an energy deficient Balancing Authority in EEA 3, the RC would accept an Operating Plan that includes planned manual or automatic post-Contingent load shedding, provided the Contingency would not result in instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System. This evaluation will be coordinated with any impacted TOPs and/or RCs [NERC Standard EOP-011-4 Attachment 1].

If a TOP desires less stringent performance criteria for a specific Credible MC, the TOP must coordinate with impacted BAs/TOPs, and obtain approval from the RC, to allow less stringent performance criteria that does not result in System-wide instability, Cascading, or uncontrolled separation. A credible MC is to be mitigated to 100% of the facility’s highest Emergency Rating, or up to 125% if there is a post contingency Operating Plan in place with the RC. The TOP of the monitored facility is responsible for requesting the less stringent performance criteria and for developing the post contingency Operating

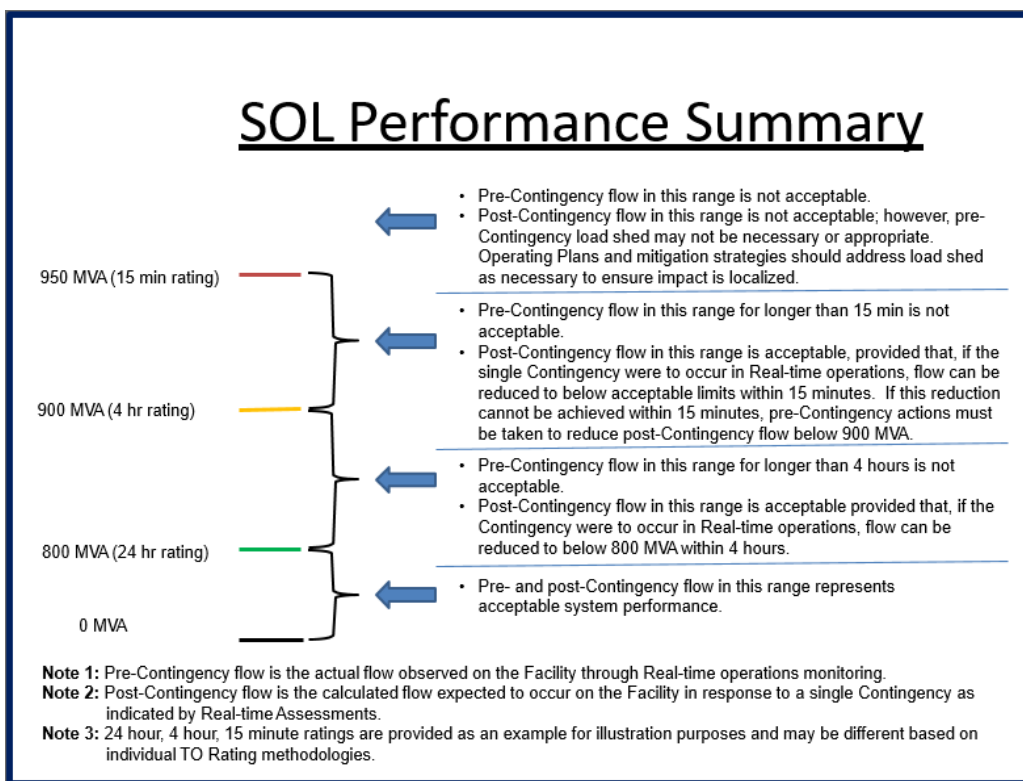
<sup>3</sup> Note that these pre- and post-Contingency performance requirements are applicable to BES Facilities.

<sup>4</sup> Except for TOP exclusions, generator step-up transformers, and exclusions denoted in [NERC BES reference document](#).

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Plan. A valid post-contingency Operating Plan must consider the time duration of the Highest Emergency Rating, and post-contingency flow must be reduced at least to the next highest ER within the associated duration of the HER. Once this request is reviewed and approved by the RC, this less stringent criteria will be used in the OPA and real-time timeframes.

Below, Figure 1: SOL Performance Summary for Facility Ratings provides an example of acceptable pre- and post-Contingency performance for a sample set of Facility Ratings. The Facility Ratings shown in the example are selected for illustration purposes only.




**Figure 1: SOL Performance Summary for Facility Ratings**

## H. SOL Exceedance

SOL exceedance occurs when acceptable system performance requirements as described in Section G of this document are not being met in seasonal studies, special studies, outage studies, OPAs or RTAs. This SOL Methodology considers an SOL exceedance to be a condition characterized by any of the following:

1. Actual/pre-Contingency flow on a Facility exceeds the highest applicable Emergency Rating.
2. Actual/pre-Contingency flow on a Facility exceeds the Normal Rating and has exceeded the time duration of available Emergency Ratings.

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3. Calculated post-Contingency flow on a Facility exceeds the highest applicable Emergency Rating.
4. Actual/pre-Contingency bus voltage is outside the emergency System Voltage Limits.
5. Actual/pre-Contingency bus voltage is outside the normal System Voltage Limits, but within the emergency System Voltage Limits, for longer than the default time duration of 30 minutes (unless the TOP provides a different time duration for the emergency System Voltage Limit).<sup>5</sup>
6. Calculated post-Contingency bus voltage is outside emergency System Voltage Limits.
7. Operating parameters indicate a predetermined stability limit has been exceeded.
8. Operating parameters indicate a Contingency could result in instability, Cascading or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System. This is also known as Insecure Operating State.
9. Operating parameters indicate an IROL has been exceeded.

### **Communication of SOL Exceedance**

SOL exceedances are required to be communicated to the RC Operator within the following timeframes specified. The notification requirements are categorized based on the level of risk to reliability of the Bulk Electric System.


**Category 1:** Notify as soon as possible, but no more than 15 minutes after discovering exceedance.

- IROL exceedance [NERC Standard FAC-011-4 R.7.1.1]
- Actual exceedance of a predetermined stability limit or verified calculated post-contingency results indicates potential for instability [NERC Standard FAC-011-4 R.7.1.2]
- Verified Insecure Operating State [NERC Standard FAC-011-4 R.7.1.3]<sup>6</sup>
- Calculated post-contingency exceedance of highest emergency Facility Rating  $\geq 125\%$
- Actual/pre-Contingency exceedance above the highest applicable Emergency Rating [NERC Standard FAC-011-4 R.7.1.4]

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<sup>5</sup> If a time duration for the Emergency System Voltage Limit is not submitted by the TOP, a default time duration of 30 minutes will be used.

<sup>6</sup> Insecure Operating State defined in RC West Operating Procedure RC0310 Mitigating SOL and IROL Exceedances, Section 3.9.

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- Actual/pre-Contingency exceedance above the Normal Rating and of a duration that exceeds the time duration of available Emergency Ratings [NERC Standard FAC-011-4 R.7.1.4]
- Actual/pre-Contingency bus voltage is outside the emergency System Voltage Limits [NERC Standard FAC-011-4 R.7.1.4]
- Actual/pre-Contingency bus voltage is below the normal low System Voltage Limits and of a duration that exceeds the time duration of available emergency System Voltage Limits. [NERC Standard FAC-011-4 R.7.1.5]
- Calculated post-contingent exceedance of 100-125% of the highest emergency Facility Rating, if not resolved within 30 minutes. [NERC Standard FAC-011-4 R.7.2.1]
- Actual/pre-Contingency bus voltage is above the normal high System Voltage Limits and of a duration that exceeds the time duration of available emergency System Voltage Limits, if not resolved within 30 minutes. [NERC Standard FAC-011-4 R.7.2.2]

**Category 2:** Notify within 30 minutes.


- Calculated post-Contingency exceedance of emergency High or Low System Voltage Limit, if not resolved within 30 minutes. [NERC Standard FAC-011-4 R.7.2.1]
- Provide within 30 minutes of RC request for a post-contingent mitigation plan for a calculated post-contingency (RTCA) exceedance that a TOP is unable to mitigate in a timely manner by implementing the primary Operating Plan.

## I. Allowed Uses of Automatic Mitigation Schemes

This section is applicable to mitigation schemes that automatically initiate mitigation actions in response to system conditions or Contingency events [NERC Standard FAC-011-4 R4.7].

The following items describe the allowed use of automatic mitigation schemes in the Operations Horizon, including both non-load-shed automatic schemes and load-shed automatic schemes:

1. If a TOP relies upon an automatic scheme for providing acceptable performance for single Contingencies or credible MCs, then the actions of the automatic scheme must be modeled in assessment tools or otherwise included in the TOP's analysis and the RC's analysis as applicable.
2. If at any time OPAs or other prior analyses indicate that the automatic scheme either fails to mitigate the reliability issue, potentially causes other reliability issues or could result in a more significant reliability risk, or if the automatic scheme is expected to be unavailable, the TOP must develop an Operating Plan in coordination with impacted TOPs and the RC, that contains pre-Contingency mitigation actions to address the reliability issue.
3. If at any time RTAs indicate that the automatic scheme either fails to mitigate the reliability issue, potentially causes other reliability issues or could result in a more significant reliability risk, or if

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the automatic scheme is unavailable, the TOP must initiate an Operating Plan in coordination with impacted TOPs and the RC, to take pre-Contingency mitigation actions to address the reliability issue.

4. Automatic schemes that have a single point of failure may not be utilized to prevent System instability, Cascading, or uncontrolled separation from occurring in response to single Contingencies or credible MCs. If any TOP seeks an exception, the TOP shall coordinate with the RC and request to be granted an exception until the necessary redundancies can be put in place and the automatic scheme classification is updated per the applicable standard or regional criteria. Exceptions may be made only for conditions that would otherwise require pre-Contingency load shedding. If operational situations arise where an automatic scheme that has a single point of failure must be relied upon to avoid pre-Contingency load shedding, such conditions must be coordinated and approved for use by the RC.
5. If an automatic scheme is relied upon to prevent System instability, Cascading, or uncontrolled separation in the transient or post-transient timeframe, the TOP studies must assess those timeframes to ensure that the automatic action occurs in time to prevent System instability, Cascading, or uncontrolled separation. [NERC Standard FAC-011-4 4.6]
6. Several automatic schemes are intended and designed to address certain non-credible MCs (including extreme event Contingencies). In the Operations Horizon, these schemes are allowed to be relied upon to meet their intended design objectives for those non-credible and extreme event Contingencies; however, this SOL Methodology does not require assessment of – and therefore, determination of acceptable performance for – non-credible and extreme event Contingencies in the Operations Horizon.


#### **Requirements Specific to Non-Load-Shed Automatic Schemes**

Non-load-shed schemes include those that do not shed load as part of the mitigation action of that scheme. Examples of such schemes include generation drop schemes and transmission reconfiguration schemes.

1. Non-load-shed automatic schemes are not as restricted in their use as are load-shed automatic schemes. Accordingly, use of non-load-shed automatic schemes is allowed for the same conditions where the use of load-shed automatic schemes is allowed.
2. Non-load-shed schemes may be used as an acceptable automatic post-Contingency mitigation action, provided the general requirements listed in items 1-6 above are met.
3. If a TOP intends to use a non-load-shed scheme in a manner for which the scheme was not intended and designed, and that intended use impacts other TOPs, the TOP must coordinate with impacted TOPs prior to using that scheme.

#### **Requirements Specific to Load-Shed Automatic Schemes**

Load-shed schemes include any scheme that automatically sheds load in response to Contingency events. Such schemes include, but are not limited to, load-shed Remedial Action Schemes (RAS), Underfrequency Load Shedding (UFLS) schemes, Undervoltage Load Shedding (UVLS) schemes

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(including UVLS Programs) or other non-RAS schemes that automatically shed load in response to Contingency events.


In principle, the use of load-shed schemes in the Operations Horizon must take into consideration how the schemes are intended and designed to be utilized.

The following items describe the allowed use of load-shed schemes in the Operations Horizon:

1. Load-shed schemes shall be used and relied upon for the conditions/events for which the load-shed schemes are intentionally designed. There may be scenarios where it is appropriate to use or rely upon load-shed schemes to address Contingency events for which the load-shed scheme was not designed. Such instances should be minimized and should be thoroughly investigated and studied in the Operations Horizon to ensure that use of these schemes is reliable, prudent, consistent with sound engineering judgment and utility practice, and reflects appropriate risk management principles.
2. There may be conditions where the operational consequences of some load-shed schemes are such that TOPs, in collaboration with the RC, may choose to implement an Operating Plan that prevents the load-shed scheme from triggering for a given operating condition or Contingency event.
3. Some load-shed schemes are intended and designed to address certain credible MCs. If a load-shed scheme is intended and designed to address a specific credible MC, then the load-shed scheme is allowed to support economic operations and is allowed for consideration in the Operations Horizon, for:
  - a. Assessing acceptable post-Contingency system performance for those Contingencies,
  - b. Determining whether a Stability Limit or an IROL needs to be established, and
  - c. Calculating the value of the Stability Limit or the IROL, once it has been determined that there is a need to establish a Stability Limit or an IROL.
4. Load-shed schemes may be relied upon and utilized in operations for single Contingencies if the scheme's impact is limited to a small amount of load in the local network area. However, load-shed schemes may not be relied upon or utilized in operations for single Contingencies to support economic operations.<sup>7</sup>

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<sup>7</sup> The intent is to, if possible, limit reliance on such load-shed schemes to those that were designed and implemented per the allowances specified in Table 1 of TPL-001-5.1 for P1 Contingencies. While Table 1 TPL-001-5.1 indicates that Non-Consequential Load Loss is not allowed for single P1 Contingencies, the table includes footnote 12 which states, "An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the

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5. There are times when a planned or forced outage of a Facility causes a MC in planning to become a single Contingency in operations.<sup>8</sup> When this type of scenario occurs for MCs for which a load-shed scheme was designed, the scheme can be relied upon and utilized in operations according to the following:
  - a. When a forced or urgent<sup>9</sup> outage of a Facility causes a MC in planning to become a single Contingency in operations, the load-shed scheme can be relied upon to provide for acceptable system performance for the next single Contingency; however, System Operators shall take appropriate action up to, but not necessarily including, load shedding to (if at all possible), re-position the system in response to the forced or urgent outage such that the load-shed scheme is not required to provide for acceptable system performance for the next single Contingency.<sup>10</sup> In such conditions, Real-time studies, operations/engineering judgment and the operational consequences of the load-shed scheme should be considered in the overall risk management exercise when determining the appropriate course of action.
  - b. When a planned outage of a Facility causes a MC in planning (for which a load-shed scheme was designed) to become a single Contingency in operations, TOPs shall develop an outage-specific Operating Plan to take appropriate action up to, but not including load shedding, to (if at all possible) pre-position the system so that the load-shed scheme is not required to provide for acceptable system performance for the next single Contingency for the duration of the planned outage. In planned outage scenarios, load-shed schemes are not allowed to be used to support economic operations for the next worst single Contingency. If possible, reliance on load-shed schemes for single Contingencies during planned outages should be limited to addressing local area Facility Rating exceedance issues. Any planned outage that requires reliance on load-shed schemes to prevent instability, Cascading or uncontrolled separation during planned outages for the next single Contingency will be allowed only upon the express review and approval by the RC.
    - i. If possible, planned outages should be scheduled for a time when system conditions are such that a load-shed scheme is not necessary to provide for acceptable system performance for the next single Contingency during the planned outage.

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planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.” This footnote is intended to provide guidance but does not explicitly limit the amount of load that can be shed for a single contingency in the Operations Horizon.

<sup>8</sup> Example: A UVLS Program is designed in the planning horizon to prevent a common structure Contingency from resulting in instability. The structure carries two transmission lines. One of these two lines is removed from service on a planned or forced outage. From an operations perspective, the loss of the remaining line now represents a single Contingency during the period that the outage of the other line is in effect.

<sup>9</sup> Reference IRO-017-1 Outage Coordination Process for description of forced and urgent outage types.

<sup>10</sup> Appropriate actions may or may not include sectionalizing. If sectionalizing places more load at risk, then reliance on load-shed scheme is acceptable if the scheme was designed for the intended purpose.

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- ii. If it is not possible to schedule the planned outage as described above, and reliance on load-shed scheme cannot be avoided for the next worst single Contingency during the planned outage, the load-shed scheme action must be simulated and studied in TOP assessments and in RC assessments as applicable, and those studies must demonstrate that the load-shed scheme action provides for acceptable post-Contingency system performance.

## J. Coordination Responsibilities

1. TOPs are expected to establish Facility Ratings for use in the Operations Horizon in coordination with their respective TOs and with adjacent TOPs.
2. TOPs are expected to establish System Voltage Limits in coordination with their respective TOs and with adjacent or impacted TOPs.

If TOPs are unable to reach a resolution on matters related to TOP-to-TOP collaboration and coordination, the TOPs shall consult with RC West to help resolve the issue.

## K. System Operating Limits


SOLs used in the Operations Horizon include Facility Ratings, System Voltage Limits and Stability limits. This section describes each of these three types of SOLs.

### Facility Ratings

It is important that the TOPs and the RC use the same set of Facility Ratings for assessments within the Operations Horizon, including seasonal studies, outage coordination studies, special studies, OPAs and RTAs. While it is acceptable to use general or more stringent Facility Ratings to flag potential reliability issues, the established Facility Ratings must be used for assessments within the Operations Horizon.

TOPS shall submit the following Facility Ratings together with the associated time duration [NERC Standard FAC-011-4 R2]:

1. Normal Rating: the rating as defined by the equipment owner that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or element can support or withstand through the daily demand cycles without loss of equipment life.
2. Emergency Rating: The rating as defined by the equipment owner that specifies the level of electrical loading or output, usually expressed in megawatts (MW) or Mvar or other appropriate units, that a system, facility, or element can support, produce, or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved. Depending on the facility rating methodology TOPs adopted, there could be multiple emergency ratings for the equipment depending on the time duration the element can support or withstand. RC West takes the longest duration emergency rating for Real-time monitoring. If there are no predetermined emergency ratings, TOPs may submit the normal rating as the emergency rating.

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3. Highest Emergency Rating: The highest facility rating that the equipment could endure. This rating should only be submitted if it is different from the submitted emergency rating. If this rating is not submitted separately, the RC will utilize the shortest duration Emergency Rating.

SOLs shall not exceed associated Facility Ratings [NERC Standard FAC-011-4 R7.1.4]. More specifically, Facility Ratings are SOLs.

Emergency Facility Ratings with a time value of less than 15 minutes can only be used when its use is acceptable by both the TOP and the RC.

### Facility Ratings Used in RC West’s Full Network Model

1. RC West’s Full Network Model uses the ratings submitted by TOPs through the IRO-010-5 Data Request (Section 6).
2. RC West’s analysis tools are also able to utilize dynamic Facility Ratings in Real-time operations. If a TOP uses dynamic Facility Ratings in Real-time tools, the TOP shall coordinate with RC West to facilitate RC West’s implementation of those dynamic Facility Ratings in RC West’s models for use in Real-time operations.
3. If TOPs have seasonal ratings for facility rating, please submit seasonal facility rating so that RC West’s Full Network Model uses those ratings accordingly.

### Communication of Facility Ratings


1. TOPs are responsible for communicating to the RC any changes to the Facility Ratings used in operations. This includes any temporary Facility Ratings that may be implemented and changes to seasonal Facility Ratings (e.g., when the TOP stops using summer seasonal ratings and begins using fall seasonal ratings).
2. Refer to RC West IRO-010-5 Data Request (Section 6) for communication instructions and template.

### System Voltage Limits

NERC defines System Voltage Limits as:

*The maximum and minimum steady-state voltage limits (both normal and emergency) that provide for acceptable System performance.*

It is important that the TOPs and the RC use the same set of System Voltage Limits for assessments within the Operations Horizon, including seasonal studies, outage coordination studies, special studies, OPAs and RTAs. While it is acceptable to use general or more stringent voltage limits to flag potential reliability issues, the established System Voltage Limits must be used for assessments within the

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Operations Horizon.<sup>11</sup>

Operating within Low System Voltage Limits ensures that the buses across the BES have adequate voltage to support reliable operations of the BES.

Operating within High System Voltage Limits ensures that the system does not operate at unacceptably high voltage levels, and that the equipment connected to the bus is not subjected to voltages that exceed the equipment voltage rating. When equipment is subjected to voltages that are higher than the equipment’s voltage rating, the equipment may be damaged and may not function properly when called upon.

It is important to distinguish System Voltage Limits from voltage Stability Limits. System Voltage Limits address the steady-state voltage of the system, while voltage Stability Limits exist specifically to address voltage instability risks based on post-transient analysis. Voltage Stability Limits are addressed in a subsequent section of this SOL Methodology.

TOPs shall establish System Voltage Limits according to the following:


### Requirements for Establishing System Voltage Limits

1. TOPs are responsible for the establishment of System Voltage Limits for the BES substation buses that exist within their TOP Area. TOPs have the flexibility to modify these limits as necessary based on actual or expected conditions within the bounds of the subsequent requirements listed below, provided the changes are justified for reliability and a technically sound rationale can be provided. [NERC Standard FAC-011-4 R3.1]
2. High System Voltage Limits must NOT exceed the voltage limits (continuous or time-dependent) of connected equipment. TOPs may utilize various resources in developing System Voltage Limits including manufacturer ratings, industry standards (e.g., IEEE, CIGRE or other),<sup>12</sup> and data based on testing, performance history or engineering analysis. TOPs are encouraged to develop Normal and Emergency voltage limits based on an internal risk assessment of factors deemed relevant/important, including use of time-dependent equipment ratings. [NERC Standard FAC-011-4 R3.2]
3. System Voltage Limits are applied to BES Substation buses. RC West will exclude the following by default, unless a TOP specifically communicates to the RC in its submission that these should be included, and noting the rationale for inclusion:
  - a. Line side series capacitor buses,
  - b. Line side series reactor buses,
  - c. Dedicated shunt capacitor buses,

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<sup>11</sup> Some entities might use generic (or more stringent) voltage limits that may exist in planning models that do not reflect the System Voltage Limits that are used in actual operations.


<sup>12</sup> This is in alignment with FAC-008-5 R3 applicable to TOs for establishing Facility Ratings.

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- d. Dedicated shunt reactor buses,
- e. Metering buses, fictitious buses, or other buses that model points of interconnection solely for measuring electrical quantities, and
- f. Line/load tap buses, or buses in a radial generator/load network.

A TOP may choose to exclude other buses in its TOP area, provided the exclusion is justified for reliability and is documented, by noting the rationale in the System Voltage Limits submission to RC West.

4. While it is expected that TOPs will take steps to coordinate the development of System Voltage Limits as described in the Coordination Responsibilities section of this SOL Methodology, it is the specific responsibility of TOPs to agree on the System Voltage Limits for buses that connect to adjacent TOPs. If the TOPs cannot agree, the most limiting System Voltage Limits in kV will apply as a default. If this default poses an unacceptable restriction or a reliability issue for the interconnecting TOPs, the TOPs must collaborate with RC West to reach a resolution in situations where there are different voltage limits for a bus that connects a neighboring RC area, the most conservative limits are adopted. [NERC Standard FAC-011-4 R3.5]
5. System Voltage Limits must enable reliable BES operations. If a TOP provides System Voltage Limits that RC West determines to be detrimental to the reliable operation of the BES, RC West may request a technical justification for the use of such limits and may prescribe different System Voltage Limits.
6. System Voltage Limits must NOT exceed voltage limits identified in Nuclear Plant Interface Requirements.
7. System Voltage Limits must NOT be set to allow the triggering of Protection Systems that trip load (e.g., UVLS) or BES Facilities (e.g., for high voltage); or prevent the operation of Protection Systems. For all BES substation buses without UVLS, the Low System Voltage limits shall not be lower than 0.8 pu. [NERC Standard FAC-011-4 R3.3] and [NERC Standard FAC-011-4 R3.4]
8. **Normal System Voltage Limits:** [NERC Standard FAC-011-4 R3]
  - a. Normal System Voltage Limits are the limits used to monitor for actual/pre-Contingency SOL exceedance. An actual/pre-Contingency voltage outside the Normal System Voltage Limits is an SOL exceedance and indicates that the TOP must take action to bring the actual/pre-Contingency voltage within the normal limits.
  - b. Normal System Voltage Limits must NOT be outside the Emergency System Voltage Limits.
  - c. If a TOP submits a single normal voltage limit for a bus, it will be the Normal System Voltage Limit (SOL) and treated as continuous by TOPs and RC West. If the TOP chooses, this single limit can be associated with a time duration but will be treated as continuous by TOPs and RC West. If a TOP submits multiple normal voltage limits for a bus, the least restrictive normal voltage limit for the bus will be the Normal System Voltage Limit (SOL); used through all phases of the Operations Horizon (seasonal and other special studies, outage coordination assessments, Operational Planning Analyses, and Real-time Assessments); and treated as continuous by TOPs and RC West.

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- d. If a TOP submits Normal System Voltage Limits with time duration, the Normal System Voltage Limits must have a time duration of 15 minutes or greater.
- e. A TOP may utilize more stringent voltage values for their internal voltage schedules, targets, or desired operating ranges, but RC West and TOPs will only use the Normal System Voltage Limits as SOLs.


**9. Emergency System Voltage Limits: [NERC Standard FAC-011-4 R3]**

- a. Emergency System Voltage Limits are the limits used to monitor for post-Contingency SOL exceedance. A calculated post-Contingency voltage outside the Emergency System Voltage Limits is an SOL Exceedance and requires pre-Contingency action to bring the calculated post-Contingency voltage within the emergency limits.
- b. A TOP may designate Emergency System Voltage Limits with time duration(s). Emergency System Voltage Limit must have a time duration of 15 minutes or more.

Table 1, following summarizes monitoring System Voltage Limits, in Real-time and in studies.

**Table 1: System Voltage Limits Monitor and Study Summary**

Normal High/Low	Emergency High/Low
<u>Real-time:</u> <ul style="list-style-type: none"> <li>• Primarily monitored in SCADA, or State Estimation (if SCADA is unavailable), for actual exceedance</li> </ul> <u>Study:</u> <ul style="list-style-type: none"> <li>• Monitored for pre- Contingency exceedance</li> </ul>	<u>Real-time:</u> <ul style="list-style-type: none"> <li>• Primarily monitored in SCADA, or State Estimation (if SCADA is unavailable), for actual exceedance</li> <li>• Monitored in RTCA (or equivalent) for calculated post- Contingency</li> </ul> <u>Study:</u> <ul style="list-style-type: none"> <li>• Monitored for pre-Contingency exceedance</li> <li>• Monitored in Contingency Analysis for calculated post- Contingency exceedance</li> </ul>


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### Communication of System Voltage Limits

1. TOPs shall review their System Voltage Limits annually at a minimum and document changes to their System Voltage Limits. TOPs must use the template posted to RC West’s portal titled “System Voltage Limits TEMPLATE.xlsx” to communicate their System Voltage Limits. TOPs shall post the populated template for its TOP Area in the “SOL Methodology” library in the secure RC West portal and upload to the RIMS application<sup>13</sup> (Per the RC model update process). TOPs shall submit the completed spreadsheet with the filename “System Voltage Limits – TOPxyz.xlsx.”
2. When a TOP posts an update to the “System Voltage Limits” folder, the TOP must delete prior versions and fill out the “Revision History” tab in the updated System Voltage Limits. Note that prior versions deleted from the folder are available for viewing in the Archive library.
3. Any known changes to the System Voltage Limits should be posted six months before the start of each operating season. Note that the RC West requires each System Voltage Limit variance and exclusion to be accompanied by a supporting rationale.
4. The “*System Voltage Limits TEMPLATE.xlsx*” contains four worksheets: overview, default, variances, and revision history.
  - a. **Overview:** This worksheet provides brief overview of how the submitted System Voltage Limits are utilized in the RC West RTCA/HANA applications.
  - b. **Default System Voltage Limits:** This worksheet is used by the TOP to submit default normal and emergency System Voltage Limits for each voltage class utilized in the TOP Area. When implemented into RC West database, the data can be viewed in the Active SOL Bias tables in RC West RTCA/HANA application. Time duration information and additional System Voltage Limits can be submitted using the worksheet; however, these are for information and not used in RC West RTCA/HANA application.
  - c. **Variance System Voltage Limits:** This worksheet is used by the TOP to submit variances, if any, from the default System Voltage Limits. When implemented into the RC West database, the data can be viewed in the Busbar Voltage Limit tables in the RC West RTCA/HANA application. Time duration information and additional System Voltage Limits can be submitted using the worksheet; however, these are for information and not used in RC West RTCA/HANA application.
    - i. A TOP should include a busbar on the Variance tab if either of the following are true: (1) the busbar should have a different system voltage limit than what the TOP has on the default tab or (2) a busbar in the model should not be monitored for system voltage limit (voltage SOL) exceedances.
    - ii. To activate a variance for a specific bus, set the "Variance/Activate Limit" flag to "Y".

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<sup>13</sup> For information on submitting model changes via RIMS, refer to user guides and training videos available on RC Portal > Training > Model Changes & RIMS.

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- iii. If there are any station buses that do not require System Voltage Limits, set the "Monitor/Limit Checking" flag to "N."
- iv. When submitting System Voltage Limits for new stations/equipment, the TOP should highlight the station/equipment and include company, zone, station, and bus information in the spreadsheet submitted to RC Portal and RIMS.
- d. **RTCAHANA Zones:** This is a reference worksheet which includes company, zone and voltage level information which can be used as a reference by the TOP for submitting system wide default System Voltage Limits for its area. The data on this worksheet is exported from the RTCA/HANA database (Active SOL Bias tables) after every database build and posted to the RC Portal.
- e. **RTCAHANA Busbars:** This is a reference worksheet which includes station and busbar information which can be used as a reference by the TOP for submitting Variance System Voltage Limits for specific buses in its area. The data on this worksheet is exported from RTCA/HANA database (Busbar Voltage Limit tables) after every database build and posted to the RC Portal.

### **Stability Limits**

Transient Stability Limits and Voltage Stability limits are SOLs. Transient and Voltage instability in Real-time operations is generally assessed in one of two ways, either of which is acceptable:


1. Using advanced Real-time applications that assess the system's response to simulated Contingency events, which may include system transfer scenarios.
2. Using predetermined limits established in offline studies which, if operated within, are expected to result in acceptable Stability performance in response to the simulated Contingency event for expected system conditions.

If the method described in Item 2 is used, it is the responsibility of the TOP to determine when it is appropriate to use Stability limits established in prior studies, or whether expected system conditions warrant performing new studies to revise those Stability limits used in Real-time operations.

Both methods must meet the performance criteria specified in this SOL Methodology.

When interface/cut plane Stability limits are established, they should be established in a manner that most accurately and directly addresses the instability risk. For example, a Stability limit should be established on an interface/cut plane that most accurately and directly monitors the instability risk, which may not coincide with defined WECC paths. Neither historical presumptions/practices regarding system monitoring nor commercial/contractual arrangements should influence where Stability limits are established to monitor for reliability most accurately and directly.

Stability limits have been established for certain interfaces/paths based on Operations Planning Studies. The applicable contingencies identified in section F that have an impact on stability limits establishment of the interface/paths are required to be included in the assessment. The stability limits are established to meet the performance criteria specified in the transient analysis and post – transient analysis methodology portion and cover the most severe system condition. [NERC Standard FAC-011-4 R4.2]

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When interface/cut plane Stability limits are impacting more than one TOP in its Reliability Coordinator Area or other Reliability Coordinator Areas, the RC will validate the limit that is set by the Transmission Operator(s). It is TOPs' responsibility to submit stability limits that impact other TOPs. If impacted TOPs cannot agree on a Stability limit, the TOPs involved are expected to coordinate with the RC to reach a resolution. If agreement/resolution cannot be achieved through collaboration, the RC has the authority to make the final determination of the stability limit. [NERC Standard FAC-011-4 R4.3] [NERC Standard FAC-014-3 R4]


Stability limits must be established under the condition that expected loading, generation and level of transfer conditions shall be screened for the period under study to determine the conditions under which instabilities occur. The TOP and/or the RC may run studies on only those specific set of loading and generation conditions under which instabilities occur for subsequent studies. Stability limit studies must include any changes to System topology such as applicable Facility outages that are planned for the period of the study. [NERC Standard FAC-011-4 R4.4]

If an allowable RAS or other automatic post-contingency mitigation is relied upon to address an instability phenomenon, the stability studies must simulate the actions of these schemes to ensure that the schemes adequately address the reliability issues. Associated study reports or Operating Plans must include a description of the actions and timing of these schemes. [NERC Standard FAC-011-4 R4.6.]

Stability limits are established under the assumption that the use of under frequency load shedding (UFLS) programs and Undervoltage Load Shedding Programs (UVLS) are not allowed. [NERC Standard FAC-011-4 R4.7]

### **Transient Analysis Methodology**


1. It is up to the TOP and/or the RC to determine if and what types of operational transient studies are required for a given season, planned outage, or operational scenario. For example, if a TOP or the RC determines (based on experience, engineering judgment and knowledge of the system) that a planned transmission or generation outage might pose a risk of transient instability for the next worst single Contingency or credible MC, the TOP shall perform the appropriate transient analyses to identify those risks.
2. Single Contingencies shall be simulated as the more severe of single line-to-ground Faults or three-phase Faults as determined by the TOP or RC. The more severe Faults will be simulated:
  - a. At no more than 10 percent from each point of connection with bus; or
  - b. The most severe of the high or low side of an autotransformer.
3. The Fault duration applied shall be based on the total known Fault clearing times or as specified in the corresponding planning studies for the applicable voltage level. For credible MC events, the appropriate clearing times must be modeled.
4. Transient studies must extend for at least 10 seconds following the initiating event or longer if swings are not damped.

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5. The dynamics parameter file used for transient studies in all phases of assessments in the Operations Horizon (seasonal studies, special studies, outage coordination studies, OPAs and RTAs) shall be based upon the approved WECC dynamics file for the applicable season.
6. The buses monitored for transient system performance are determined based on engineering judgment.

### **Transient Analysis Performance Requirements**

Transient system performance requirements are indicated following, in Table 2.

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**Table 2: Transient System Performance Requirements**

<b>Transient System Performance</b>	<b>Required for Single Contingencies and Credible MCs</b>
The system must demonstrate positive damping. The signals used generally include power angle, voltage, and/or frequency. An example of damping ratio calculation is provided in Appendix B [NERC Standard FAC-011-4 R4.1.2, R4.1.3 and R4.1.4].	Yes
<ol style="list-style-type: none"> <li>1. The BES must remain transiently stable and must not Cascade or experience uncontrolled separation as described in this SOL Methodology.</li> <li>2. System frequency in the interconnected system as a whole must not trigger UFLS as outlined in Planning Coordinator's UFLS program.</li> <li>3. Any controlled islands formed must remain stable.</li> <li>4. No BES generating unit shall pull out of synchronism</li> </ol>	Yes <sup>14</sup>
Transient frequency or low voltage dips and settling points shall not violate in magnitude and duration: <ol style="list-style-type: none"> <li>1. Known generator trip settings or if trip settings are unknown, generator ride-through capabilities as specified by PRC-024-3 Attachments 1 and 2 or its successor.</li> <li>2. Nuclear plant interface requirements</li> </ol>	Yes <sup>15</sup>
<b>General Notes:</b> <ol style="list-style-type: none"> <li>1. UVLS or other automatic mitigation actions are permitted as specified within RC West's SOL/IROL methodology.</li> <li>2. A generator being disconnected from the system by Fault clearing action or by a RAS is not considered losing synchronism. Additionally, small (&lt;25 MW) non-BES generators that may trip are not considered as losing synchronism.</li> <li>3. If known BES equipment trip settings are exceeded, the appropriate actions must be modeled in the simulations.</li> </ol> <p>For generators that the GO or NPIR have identified as not being able to meet the PRC-024-3 requirements, either the unit must be tripped, or the Point of Interconnection (POI) frequency verified against the unit established trip values and the appropriate action taken.</p>	

<sup>14</sup> A TOP can coordinate with the RC and impacted TOPs to allow a BES generating unit to pull out of synchronism for a specific Credible MC.

<sup>15</sup> A TOP can coordinate with the RC and impacted TOPs to allow generators to be tripped for a specific Credible MC.

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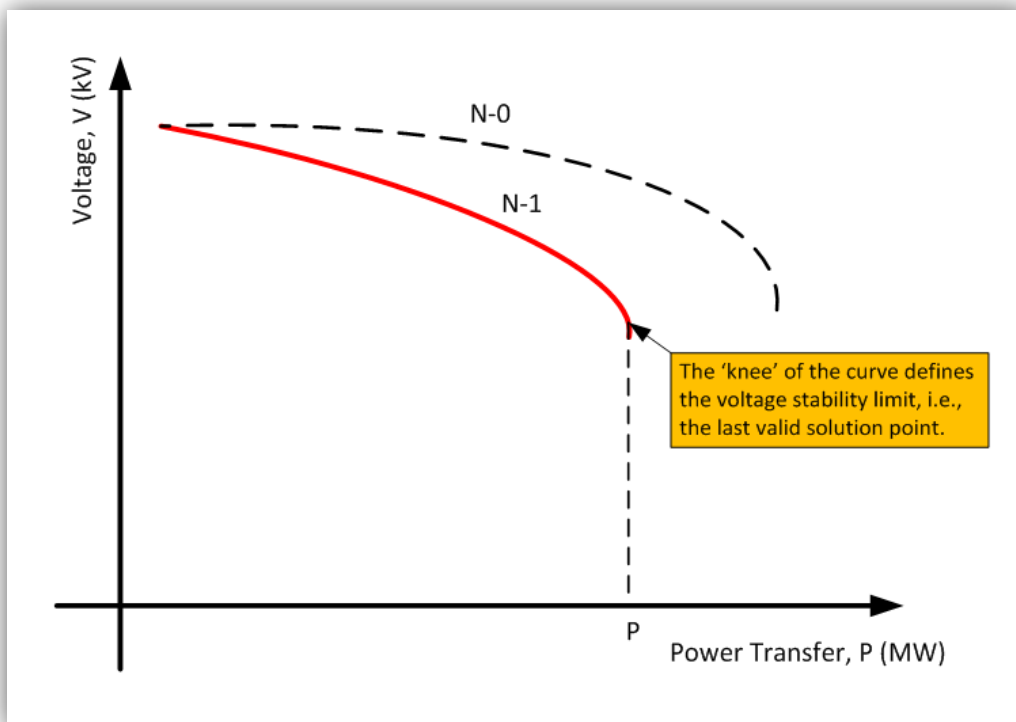
### Establishment of Transient Stability Limits

1. Transient Stability Limits are established to meet the transient system performance requirements in Table 2: Transient System Performance Requirements.
2. Transient Stability limited SOLs can include margins. Operating Plans shall specify if a transient Stability limited SOL includes margin.


### Voltage Stability Analysis

1. Voltage Stability Limits are SOLs and can become IROLs. Voltage Stability Limits are established using transient (for fast voltage collapse risks) and post-transient analysis techniques. Reference Figure 2: Sample P-V Curve as an example of a MW power transfer approach to defining a voltage Stability Limit. [NERC Standard FAC-011-4 R4.1.1 and R4.1.2]
2. Voltage Stability limited SOLs can include margins. Operating Plans shall specify if a voltage Stability limited SOL includes margin.

**Reference Figure 2:** Sample P-V Curve below for an example of a PV curve for determining voltage Stability Limits. (Shown on following page)



**Figure 2: Sample P-V Curve**


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### Communication of Transient and Voltage Stability Limits

1. When TOP studies indicate the presence of transient or voltage instability risks (whether contained or uncontained) for planned outages or expected system conditions, the TOP shall communicate the study results to RC West and to impacted TOPs for further coordination and review. This communication should occur in a timely manner to allow for proper coordination and preparation prior to Real-time operations.
2. TOPs shall communicate the following information for any identified transient or voltage Stability limit:
  - **Instability Risk** – a description of the instability risk that is addressed with the Stability limit,
  - **Contingencies** – the Contingency(ies) that the Stability limit is protecting against,
  - **Outages** – any transmission or generation outages associated with the Stability limit,
  - **Stability Limit Values** – any pre-determined fixed value(s) for the Stability limit. Describe if the Stability limit established in real-time or calculated dynamically. In instances where there is no Stability Limit established to address the instability risk, RC still needs to know about the risk and how that risk is being addressed.
    - Example, a forced transmission line outage has rendered a condition where a small load pocket is now served by two transmission lines instead of the usual three lines. A Contingency on either of the remaining two lines will result in local voltage collapse on the small load pocket. The only way of preventing voltage collapse is to shed load pre-Contingency. The TOP and the RC agree not to shed load pre-Contingency to prevent the single Contingency from resulting in local, contained voltage collapse.
  - **Monitoring Method** – description of the method System Operators use for monitoring the Stability limit, and
  - **Other Pertinent Information** – any other pertinent operating conditions associated with the Stability limit, e.g., applicable to a certain season, a period of weeks/days/hours, certain loading conditions or other conditions, etc.
3. TOPs must use the template posted to RC West’s portal titled, “Stability Limits Communication - Template.xlsx” to communicate their Stability Limits. If the stability limits have impact on other TOPs, it needs to be clarified in the “other pertinent information” column. TOPs shall post the populated template for its TOP Area in the “SOL Methodology” library in the secure RC West portal. TOPs shall submit the completed spreadsheet with the filename “Stability Limits – TOPxyz.xlsx.”
4. Transient or voltage Stability limit(s) identified as part of outage studies or Operational Planning Analyses (OPA), studies shall be communicated to RC West via Outage Management System (OMS).
5. Transient or voltage Stability limit(s) identified as part of Real-time studies shall be communicated to RC West via phone, and then OMS.<sup>16</sup>

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<sup>16</sup> Phone then OMS notification is aligned with RC West’s Notifications for Real-time Events procedure.

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6. Non-static transient or voltage Stability limit(s) are typically communicated to RC West via ICCP.

### Post-Transient Analysis Methodology

The post-transient period is the timeframe after any initial swings and transient effects of a Contingency are over, but prior to AGC or operator actions. Post-transient analysis is performed through a governor power flow study.

1. The starting point of the analysis is the system condition with the Contingency modeled and considering the effects of allowable automatic actions as described in the Allowed Uses of Automatic Mitigation Schemes section of this SOL Methodology, e.g., UVLS, UFLS and RAS actions.
2. The Contingencies being studied shall be run with the area Interchange controls and phase shifters controls disabled. Tap-Changer Under Load (TCUL), shunt capacitors, shunt reactors and Static Var Compensators (SVC) that are automatically controlled may be allowed to switch provided the automatic control settings are accurately modeled and the devices will switch within 20 seconds or less<sup>17</sup> in response to low voltage and will switch automatically in response to high voltage. A TOP may coordinate with the impacted TOPs and the RC ahead of real-time to allow device(s) to switch with time delays greater than 20 seconds in response to low voltage, provided the device is not relied on to prevent System-wide instability, Cascading, or uncontrolled separation. Generators and SVCs shall be set to regulate the terminal bus voltage unless reactive droop compensation is explicitly modeled, or SVC control signals are received from a remote bus.
3. Loss of generation shall be accounted for in the power flow by scaling up the generation in the interconnected system, with PMax limits imposed, excluding negative generators and negative loads. Any increase or decrease in generation shall be done on the weighted MW margin (up/down range) or the closest equivalent based on the program used. Alternatively, units may respond in proportion to the nameplate ratings. Base-loaded units must be blocked from responding.

## L. Instability, Cascading, Uncontrolled Separation and IROLs


The following sections provide a brief characterization of instability, uncontrolled separation, or Cascading:

### **Instability**

Per the existing definition, an IROL is an SOL which, if exceeded, could result in instability.

However, there are many forms of instability, each with a wide spectrum of reliability impacts – from little

<sup>17</sup> The 20 second reaction time for switchable reactive devices is to ensure coordination with generator Maximum Excitation Limiter (OEL) settings. Typical OELs will begin to reduce a generator's reactive output to safe operating levels within a 20-second window. Reference IEEE Recommended Practice for Excitation System Models for Power System Stability Studies, IEEE Std. 421.5-2005 (Revision of IEEE Std. 421.5-1992), 2006, pp. 0\_1–85.

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to no impact, such as losing a unit due to "instability," all the way to major and devastating impact, such as losing a major portion of the BES due to instability.

It is recognized that not all types of instability pose the same degree of risk to the reliability of the BES. At the same time, it also is recognized that regardless of the type of instability, it is critical that studies/assessment determine how – or if – the instability will be contained, and to understand the impact that the instability may have on the BES.

Accordingly, transient or voltage instability that cannot be demonstrated through studies to be confined to a localized, contained area of the BES effectively has a critical impact on the operation of the Interconnection, and therefore warrants establishment of an IROL.

IROLs and risk management for local and contained instability and a possible process for determining acceptable levels of risk for IROL determination for a local area is described in Appendix E.

### **Uncontrolled Separation**

Uncontrolled separation (which includes uncontrolled islanding) occurs when studies indicate that a Contingency is expected to result in rotor angle instability or to trigger relay action which causes the system to break apart into major islands in an unintended (non-deliberate) manner. The determination of uncontrolled separation takes into consideration transient instability phenomena and relay actions that cause islands to form.

It is recognized that transient instability may result in the loss of small pockets of generation and load, or radially connected subsystems that do not warrant establishment of an IROL. In such scenarios, the loss of a unit (or group of units) may have little to no impact on the reliable operation of the interconnected system.


Uncontrolled separation can be understood by comparing it to controlled separation as described in Appendix E.

### **Cascading**

Cascading can occur when studies indicate that a Contingency results in severe loading on a Facility, triggering a chain reaction of Facility disconnections by relay action, equipment failure or forced immediate manual disconnection of the Facility (for example, due to line sag or public safety concerns). Per the definition, when Cascading occurs, the electric service interruption cannot be restrained from sequentially spreading beyond an area pre-determined by studies.

Instability can cause Cascading. When Cascading is a response to instability, Cascading will be addressed via a Stability-related IROL.

Cascading test – If powerflow studies indicate that the successive tripping of Facilities stops before the case diverges, then, the phenomenon is not considered to be Cascading, because the studies have effectively defined an “area predetermined by studies.” However, if the system collapses during the Cascading test, the area cannot be “predetermined by studies,” and therefore it is concluded that the extent of successive tripping of elements cannot be determined. When this is the case, an IROL is warranted.

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**Powerflow Cascading test:**

1. Run Contingency analysis and flag single Contingencies and credible MCs that result in post-Contingency loading more than the lower of of:
  - a. The Facility(ies)’s trip setting, or
  - b. 125 percent of the highest applicable Emergency Rating.
2. For each flagged Contingency, open the contingent element(s) that cause(s) the post-Contingency loading and all consequent Facilities that overload more than (1) (a) or (b) above. Run powerflow without simulating any manual system adjustments.
3. Repeat step (2) for any newly overloaded Facility(ies) more than (1) (a) or (b) above. Continue with this process until no more Facilities are removed from service or until the powerflow solution diverges.
4. If the subsequent tripping of Facilities stops prior to case divergence, then it can be concluded that the area of impact is predetermined by studies, and thus Cascading does not occur. If the case diverges during the Cascading test using the 125 percent of the highest applicable Emergency Rating, then further investigation into post-Contingency loading may occur (if time allows) before declaring that Cascading occurs.

**M. IROL Establishment [NERC Standard FAC-011-4 R8.1]**


IROLs are established to prevent instability, uncontrolled separation or Cascading for:

1. Single Contingencies
2. Credible MCs

IROLs are always pre-identified through studies performed one or more days prior to Real-time.

During unanticipated Real-time events where Real-time Assessments indicate that the system is at risk of instability, uncontrolled separation, or Cascading for the next single Contingency or credible MC, the RC is expected to bring the system to a secure state with the same sense of urgency as it would address an IROL utilizing the applicable Operating Plans.

The RC is responsible for declaring IROLs, not TOPs. TOPs are responsible for communicating and collaborating with the RC when studies (seasonal studies, special studies, outage studies or OPAs) identify instability (whether contained or uncontained), Cascading or uncontrolled separation as described in this SOL Methodology. Upon this communication, the RC then collaborates with the TOPs to determine if an IROL needs to be established to address these risks. [NERC Standard FAC-014-3 R1]

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### Types of IROLs:

Since IROLs are a subset of SOLs, the following provides a brief characterization of each type of IROL that if exceeded could lead to instability, uncontrolled separation, or Cascading:

#### **Transient Stability IROLs**

Establish to prevent:

- A. The loss of synchronism (from rotor angle instability or associated relay action) that results in subsequent uncontrolled tripping of BES Facilities (Cascading), or in uncontrolled separation as described in this SOL Methodology.
- B. Widespread voltage collapse that occurs in the transient timeframe.

A transient Stability IROL is not warranted to prevent one or more units from losing synchronism and tripping offline, if studies demonstrate that the transmission system remains stable after the units are lost.

#### **Voltage Stability IROLs**

Establish to prevent:

- A. An undeterminable area or a wide area of the BES experiencing voltage instability.
- B. Voltage instability that consequently leads to Cascading or uncontrolled separation.

#### **Facility Rating-Based IROLs**


Establish to prevent:

- A. Non-stability-related Cascading due to excessive post-Contingency loading of Facilities. Cascading that consequently leads to instability or uncontrolled separation.

Appendix E contains additional information including possible IROL study methodologies and examples.

## **N. IROL $T_v$ in the RC West Area [NERC Standard FAC-011-4]**

The IROL  $T_v$  in the RC West Area shall be less than or equal to 30 minutes [NERC Standard FAC-011-4 R8.2]. The default IROL  $T_v$  value is 30 minutes. However, shorter duration IROL  $T_v$  values may be established in coordination with the impacted TOPs based on relay/protection settings and other considerations.

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## O. RC West Process for Addressing Corrective Action Plans Submitted by Planning Coordinators (PC) and Transmission Planners (TP) [NERC Standard FAC-014-3 R7]

FAC-014-3 Requirements R7 require PCs and TPs to annually communicate the Corrective Action Plans developed to address any instability identified in its Planning Assessment of the Near-Term Transmission Planning Horizon to each impacted Transmission Operator and Reliability Coordinator.


RC West implements the following process for each Corrective Action Plans identified by the PC or TP:

1. RC West communicates with the PC/TP to understand the Corrective Action Plan, the type of instability addressed by the Corrective Action Plan (e.g., steady-state and/or transient voltage instability, angular instability including generating unit loss of synchronism and/or unacceptable damping), the associated stability criteria violation requiring the Corrective Action Plan (e.g., violation of transient voltage response criteria or damping rate criteria), the planning event Contingency(ies) associated with the identified instability requiring the Corrective Action Plan and the System conditions and Facilities associated with the identified instability requiring the Corrective Action Plan.
2. RC West includes contingencies identified in the Corrective Action Plan that are deemed to be credible into stability limits determination based on RC West's SOL Methodology in the Operation Horizon. This may require RC West to perform additional studies in collaboration with the associated TOPs, taking into consideration input from the PC/TP.
3. RC West establishes stability limits based on the results of this collaboration.

## P. RC West Role in Ensuring SOLs are Established Consistent with this SOL Methodology

The RC must ensure that SOLs and IROLs for its RC Area are established and that the SOLs and IROLs are consistent with its SOL Methodology. RC West performs the following functions to meet this requirement [NERC Standard FAC-014-3 R1 and R4]:

1. RC West ensures that Facilities in the Full Network Model, which is RC West's Energy Management System (EMS) model, are associated with the Facility Ratings as provided by TOPs, consistent with this SOL Methodology.
2. RC West performs a coordination and facilitation role in the seasonal planning process for its RC Area as needed. See Operating Procedure [RC0680 RC Guidelines for Seasonal Assessment and Coordination Process](#).
3. RC West has a predominant role in the IRO-017 Outage Coordination Process for the RC Area.
4. RC West ensures that buses in the Full Network Model are associated with the System Voltage Limits provided by TOPs, consistent with this SOL Methodology.

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5. RC West reviews the Stability limits provided by TOPs to ensure they are established consistent with this SOL Methodology. RC West makes a final determination whether the Stability limits are declared an IROL.
6. RC West ensures RC System Operators and engineers have awareness of identified Stability Limits and IROLs.
7. RC West performs Real-time monitoring and RTAs to determine SOL exceedances and to determine if the system has unexpectedly entered into a single Contingency or credible MC insecure state. If the system has unexpectedly entered into a single Contingency or credible MC insecure state, RC West mitigates this condition within 30 minutes per internal Operating Plans.
8. RC West’s Real-time Contingency Analysis (RTCA) application provides indication of whether acceptable steady-state system performance is being achieved for the post-Contingency state given actual system conditions. RC West posts its RTCA results in the secure area of the RC West portal.
9. RC West utilizes a Real-time Voltage Stability Analysis (VSA) tool and communicates the results of this tool to impacted TOPs.


## Q. System Study Models

The RC West Full Network Model is the system model used to determine SOLs and models the entire Western Interconnection BES [NERC Standard FAC-011-4 R4.5]. Details of the Full Network Model can be viewed in the CAISO [Business Practice Manual](#) (BPM) for the Full Network Model.

TOPs should communicate a list of their non-BES facilities that can impact the BES facilities and upload them to the RC portal under the BA/TOP Operating Procedures library. In addition, TOPs should also communicate the respective needed Full Network model updates to include these Non-BES facilities in the RC West Full Network Model as required by Operating Procedure [RC0120A RC West IRO-010 Data Specification procedure](#). TOPs should communicate a list of their BES facilities that should be excluded from SOL Methodology applicability under the BA/TOP Operating Procedures library. The inclusion of the critical modeling details from other Reliability Coordination Areas follows [RC0600A Western Interconnection Modeling and Monitoring Common Methodology procedure](#).

While Facility Ratings and System Voltage Limits may not require a TOP study for their establishment, Stability limits are identified as a direct result of system studies. TOPs within the RC West Area generally use any of three study models for identifying instability risks and establishing Stability limits: their respective EMS models, RC West’s Full Network Model, and off-line models based on approved WECC operating base cases. Development of the WECC operating base cases is coordinated by the WECC Regional Entity. The cases for each season are approved by the WECC Regional Entity.

WECC operating base cases often require seasonal coordination between TOPs (typically through sub-regional study groups) to ensure the topology, ratings and dynamic files are updated. When this seasonal coordination is required for accurate development of SOLs, TOPs shall participate in the base case coordination to ensure their TOP Area is accurately modeled.

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RC West uses both the Full Network Model and the WECC operating base cases when performing system studies. The Full Network Model consists of the entire Western Interconnection BES. While the model contains some details for non-BES Facilities, such as lower voltage generation models and the sub-100 kV elements identified by the TOPs to impact the BES, much of the system at these lower transmission voltages is reduced to a mathematical equivalent. Loads served over radial lines are typically lumped at the delivery bus. The Full Network Model consists of transmission lines, transformers, circuit breakers and switches, reactive devices, generation units, step-up transformers, loads and other relevant electrical components.


Though the WECC operating base case is not a breaker-to-breaker model, it consists of similar information as mentioned above as well as additional details and modeling information necessary to perform dynamic and transient Stability studies.

1. TOPs and the RC shall use study models that include the entire RC West Area for establishing Stability limits [NERC Standard FAC-011-4 R4.5]. The study model must include any critical modeling details from other RC Areas that would impact the Facility(ies) under study. That said, it is acceptable to use models that equivalent portions of the RC West Area’s full loop model, provided that doing so does not impede capturing interactions between the TOP Area and the external systems or vice versa.

## **R. RC West Communication of SOL and IROL Information to Other Functional Entities [NERC Standard FAC-014-3 R5]**

RC West provides SOLs and IROLs to each Planning Coordinator and each Transmission Planner within its Reliability Coordinator Area, the SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months [NERC Standard FAC-014-3 R.5.1]. The information should include:

1. The value of the stability limit or IROL [NERC Standard FAC-014-3 R.5.2.1].
2. Identification of the Facilities that are critical to the stability limit or IROL [NERC Standard FAC-014-3 R.5.2.2].
3. The associated IROL Tv for any IROL [NERC Standard FAC-014-3 R.5.2.3].
4. The associated Contingency(ies) [NERC Standard FAC-014-3 R.5.2.4].
5. A description of system conditions associated with the stability limit or IROL [NERC Standard FAC-014-3 R.5.2.5].
6. The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability) [NERC Standard FAC-014-3 R.5.2.6].

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RC West provides each impacted Transmission Operator within its Reliability Coordinator Areas with the following information:

1. The value of the stability limits established when the limit impacts adjacent Reliability Coordinator Areas or more than one Transmission Operator in its Reliability and each established IROLs, in an agreed upon time frame necessary for inclusion in the Transmission Operator’s Operational Planning Analyses, Real-time monitoring, and Real-time Assessments IROL [NERC Standard FAC-014-3 R.5.3].
2. Each established stability limit or each IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator’s Operational Planning Analyses [NERC Standard FAC-014-3 R.5.4].

This includes:

- a. Identification of the Facilities that are critical to the stability limit or IROL
  - b. The associated IROL Tv for any IROL
  - c. The associated Contingency(ies)
  - d. A description of system conditions associated with the stability limit or
  - e. The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability)
3. The requested SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule. [NERC Standard FAC-014-3 R.5.5]

RC West also provides each impacted Generator Owner or Transmission Owner within its Reliability Coordinator Areas, with a list of their Facilities that have been identified as critical to the derivation of an IROL and its associated critical contingencies at least once every twelve calendar months. [NERC Standard FAC-014-3 R.5.6]


## S. Contact Information

For information about the RC West SOL Methodology for the Operations Horizon, or if you have any questions, please contact [ISORC@CAISO.com](mailto:ISORC@CAISO.com).

## T. Supporting Information

### Operationally Affected Parties


Shared with each Reliability Coordinator that requests and indicates it has a reliability-related need within 30 days of a request. [NERC Standard FAC-011-4 R9.1]

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Shared with the Public. Prior to the effective date of the SOL methodology, shared specifically with Adjacent RCs, each Planning Coordinator and Transmission Planner that is responsible for planning any portion of the Reliability Coordinator Area, Each Transmission Operator within its Reliability Coordinator Area; and Each Reliability Coordinator that has requested to receive updates and indicated it had a reliability-related need. [NERC Standard FAC-011-4 R9.2]

## Version History

Version	Change	Date
1.1	Updated to RC West logo, replaced CAISO RC with RC West, and replaced CAISO RC site to RC West portal. Removed Appendix F and replaced reference to Appendix with reference to RC0680.	11/01/19
1.2	Coordinated changes with Operations Planning Working Group: Included note about SOLs for generating facilities. Provided clarification about utilization of stability limits template for communication of stability limits identified as part of seasonal studies. Added note for TOPs to communicate any non-BES facilities that impact BES or BES facilities that should be excluded. Included minor changes and updates to Transient Stability criteria. Minor format and grammar updates.	12/01/20
2.0	Periodic Review: Major revision by Joint RTWG/OPWG Voltage SOL task force to Section K: Requirements for Establishing System Voltage Limits, including allowance to submit multiple time-dependent equipment ratings, and what is considered SOL for voltage limits. Revised process and template for submitting system voltage limits. Added rationale for line side series compensation buses inclusion to Appendix D. Added footnote to Section G, 2.b. on facilities except for TOP exclusions, generator step-up transformers, and exclusions denoted in NERC BES reference document. Approved by the Real-Time Working Group (RTWG) and OPWG.	10/01/22
3.0	Major revision by Joint RTWG OPWG SOL IROL Methodology Task Force to address changes due to FAC-011-4 and FAC-014-3 standard change. Removed reference to FAC-010-3 from Appendix E, as it has been retired. Updated TPL-001 references. (Update was approved by the RTWG).	4/01/24
3.1	Section K: Added line/load tap buses and buses in a radial network to default BES exclusions for Voltage SOL monitoring and clarified RC West process for addressing BES exclusions. Approved by Voltage SOL task force.	4/16/24
3.2	Added clarification for less stringent CMC performance requirement. Updated EOP-011 and IRO-010 reference version numbers. Minor formatting and grammar edits.	6/27/25

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Version	Change	Date
3.3	Removed clarification for less stringent CMC performance requirement from Section G, as more discussion on this topic is needed. Removed Footnote 7 regarding TOP discretion on contacting the RC for post-contingency high voltage exceedances. Footnote is no longer applicable with FAC-011-4. Minor formatting and grammar edits.	7/31/25
3.4	Section G: Added less stringent criteria implementation for credible multiple contingencies. Minor grammar edits in Appendix D. Section G changes have been coordinated with and approved by the RC West Operations Working Group (ROWG).	9/08/25

## U. Periodic Review Procedure

### Review Criteria & Incorporation of Changes

There is no specific review criteria identified for this document.

### Frequency

Review at least once every three years.

## Appendix A: Terms Used in this SOL Methodology for the Operations Horizon

### Terms defined/described in this SOL Methodology for the Operations Horizon:

Always Credible Multiple Contingency  
 Conditionally Credible Multiple Contingency  
 Credibility  
 Credible Multiple Contingency  
 Observable System Conditions  
 Operations Horizon  
 System Voltage Limit

### Terms used as defined in the NERC Glossary of Terms:


The following terms from the NERC Glossary of Terms are used in the SOL Methodology. The definitions from the NERC Glossary of Terms are not included here. Reference the NERC Glossary for the definitions.

Bulk Electric System (BES)

*This document is controlled when viewed electronically.  
 When downloaded or printed, this document becomes UNCONTROLLED.*

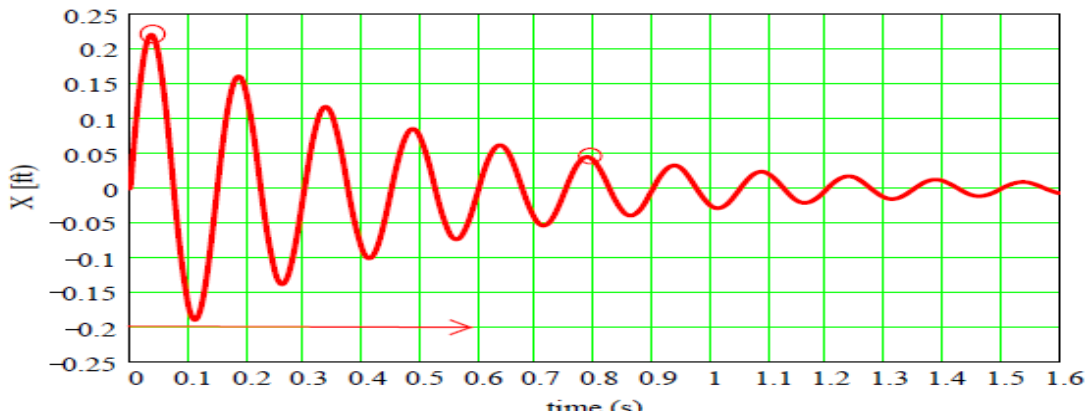
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Cascading  
 Contingency  
 Corrective Action Plan  
 Element  
 Emergency Rating  
 Facility  
 Facility Rating  
 Fault  
 Interconnection Reliability Operating Limit (IROL)  
 Near-Term Transmission Planning Horizon  
 Normal Clearing  
 Normal Rating  
 Operating Plans  
 Operational Planning Analysis (OPA)  
 Operating Procedure  
 Operating Process  
 Planning Assessment  
 Real-time  
 Real-time Assessments (RTA)  
 Reliability Coordinator (RC) Area  
 Remedial Action Scheme (RAS)  
 Stability Limit  
 System  
 System Operating Limit (SOL)  
 System Operator  
 System Voltage Limit  
 Total Transfer Capability  
 Transfer Capability  
 Transmission Operator (TOP) Area  
 Undervoltage Load Shedding (UVLS) Program

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## Appendix B: Damping Ratio Calculation Example

Measuring damping is best performed a) after all significant automatic schemes have operated; and b) should measure damping over oscillations toward the end of the simulation rather than at the beginning of the simulation. As an example, a good trigger for measuring signal damping during a ten-second run is about two seconds after the fault clears as most automatic schemes have switched and the fault should be fully cleared.



Log-dec is derived from ratio: 
$$\delta := \frac{1}{n} \cdot \ln \left( \frac{X_o}{X_n} \right)$$


$\delta = 0.305$

Note that the approximate formula =  $\delta / (2 \cdot \pi) = 0.049 \times 100 = 4.9\%$  damping ratio.

Where n = Number of periods between measurement  $X_o$  and measurement  $X_n$  Periods = 5 in example.

$X_o$  is magnitude of oscillation at first measurement.

$X_n$  is magnitude of oscillation at second measurement  $\ln = \log$  in base.

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## Appendix C: RC West Recommendations for Determining Always Credible MCs


TOPs could consider the following MC types when determining any Always Credible MCs for operations. These Contingency types serve as a starting point for the internal risk assessment for determining the Always Credible MC list:

1. Bus Fault Contingencies
2. Stuck breaker Contingencies
3. Relay failure Contingencies where there is no redundant relaying
4. Common structure Contingencies
5. Any of the MCs that have been determined by its PC to result in Stability Limits

Internal risk assessments are encouraged to be available to TOPs upon request.

### Possible Approaches for Risk Assessment Methodology

RC West will insert possible approaches and an example(s) in Revision 2 of the RC West SOL Methodology.

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## Appendix D: RC West Recommended Best Practices and Rationales

### Operating Plans

Operating Plans may include:


- Both pre- and post-Contingency mitigation plans/strategies.
  - Pre-Contingency mitigation plans/strategies are actions that are implemented before the Contingency occurs to prevent the potential negative impacts on reliability associated with the Contingency.
  - Post-Contingency mitigation plans/strategies are actions that are implemented after the Contingency occurs to bring the system back within limits.
- Details to include appropriate timelines to escalate the level of mitigating plans/strategies to ensure BES performance is maintained.
- The appropriate time element to address potential SOL exceedances.

Recommended Operating Plan checklist	
Item	Description
1	Is the purpose of the Operating Plan clearly stated?
2	Are any limits and monitored interfaces, if applicable, clearly defined?
3	Are limiting facilities and Contingencies clearly identified?
4	Are applicable RAS and their actions identified?
5	Are the impacted entities clearly identified?
6	Are the mitigation measures and timeframes for implementation clearly stated?
7	Were the technical studies that identified the need for the Operating Plan coordinated with impacted TOPs?
8	Have the mitigation measures been fully studied to resolve the issue?
9	Is the procedure necessary to prevent instability, Cascading, or uncontrolled separation?
10	Has the Operating Plan been coordinated with impacted entities?

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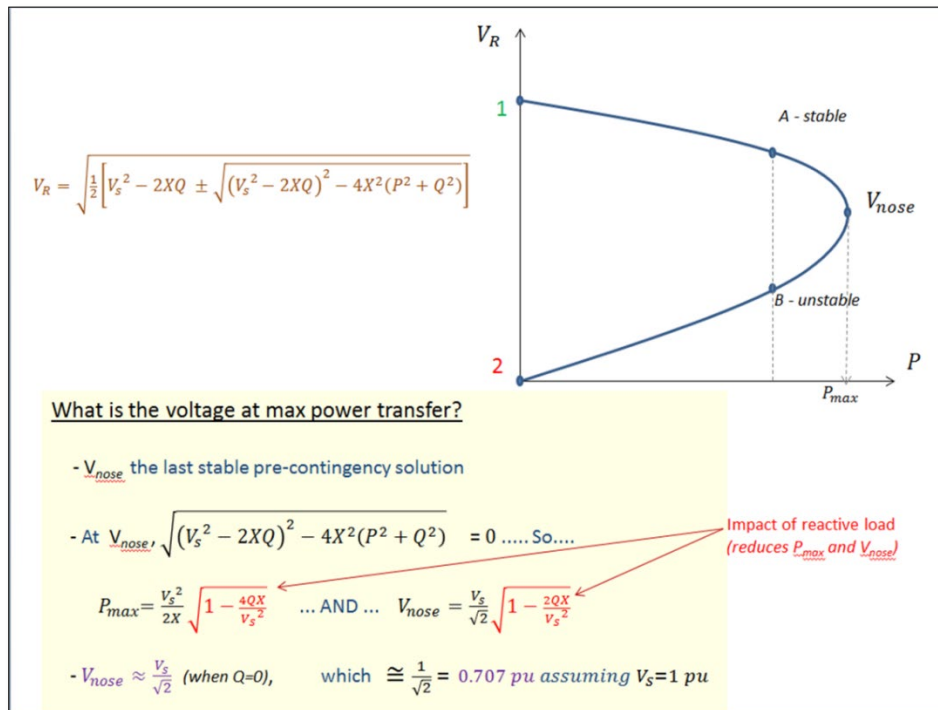
### Controlled separation versus uncontrolled separation

1. Controlled separation is achieved when there is an automatic scheme that exists and is specifically designed for the purposes of:
  - a. Intentionally separating the system.
    - i. Note that such schemes may be accompanied by generation drop schemes or UFLS that are designed to shed load or drop generation to achieve generation/load equilibrium upon occurrence of the controlled separation.
  - b. Intentionally mitigating known separation conditions.
    - i. I.e., a scheme that is designed specifically to drop load or generation to achieve generation/load equilibrium upon a known Contingency event that poses a separation risk.
2. Post-Contingency islanding due to transmission configuration does not constitute uncontrolled separation.
  - a. There are occasions where planned or forced transmission outages can render the transmission system as being configured in a manner where the next Contingency (single Contingency or credible MC) can result in the creation of an island. Operators are made aware of these scenarios through outage studies, OPAs and/or RTAs, and are expected to have Operating Plans that would address the condition in a reliable manner. Such conditions should consider the associated risks and mitigation mechanisms available; however, they are excluded from the scope of uncontrolled separation for the purposes of IROL establishment.
3. Examples of controlled separation:
  - a. Example 1: A RAS is designed specifically to break the system into islands in an intentional and controlled manner in response to a specific Contingency event(s). Supporting generation drop and/or UFLS are in place to achieve load/generation equilibrium.
  - b. Example 2: A UFLS is specifically designed to address a known condition where a credible MC is expected to create an island condition.

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**Rationale for lowest allowable System Voltage Limit**

The 0.8 pu is based on the calculated Stability point for a single unit to infinite bus uncompensated system (0.707 pu) plus 10% margin (0.777 pu) which is then rounded up rounded up to 0.8 pu. The actual system is likely less favorable than the single unit to an infinite bus, so a 10% margin is applied.



**Rationale for Including or Excluding Modelled BES Buses when Establishing System Voltage Limits**

- Line side series compensation buses inclusion:
  - Equipment connected to the line side of series capacitors that have voltage ratings which need to be incorporated into system voltage limits. This equipment may include bypass circuit breakers, bypass disconnects, and insulation coordination requirements for the series capacitor platform.
- Dedicated shunt compensation buses,
- Metering buses, fictitious buses, or other buses that model points of interconnection solely for measuring electrical quantities, and
- Other buses specifically excluded by the TOP in whose TOP Area the buses reside, provided the exclusion is justified for reliability and is documented.

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### Transient Stability Performance

The system is typically considered to demonstrate acceptable positive damping if the damping ratio of the power system oscillations is 3% or greater.

### Voltage Stability Performance Example

One representation of a voltage Stability Limit is the maximum pre-Contingency megawatt power transfer for which a post-Contingency solution can be achieved for the limiting (critical) Contingency (i.e., the last good solution established the voltage Stability Limit). P-V and V-Q analysis techniques are used as necessary for the determination of voltage Stability Limits. While megawatt power transfer represents one approach for defining a voltage Stability Limit, other units of measure (such as VAR limits) may be used, provided this approach is coordinated between the TOP and the RC.

Recommended Transient Performance for BES buses serving load:<sup>18</sup>

- a. Following fault clearing, the voltage typically recovers to 80% of the pre-contingency voltage within 20 seconds.<sup>19</sup>
- b. Following fault clearing and voltage recovery above 80%, voltage typically neither dips below 70% of pre-contingency voltage for more than 30 cycles nor remains below 80% of pre-contingency voltage for more than two seconds.
- c. For Contingencies without a fault, voltage dips at each applicable BES bus serving load should typically not drop below 70% of the pre-contingency voltage for more than 30 cycles. The voltage should also not remain below 80% for more than two seconds.

### System Stressing Methodology


The objective of this system stressing methodology is to either identify possible instability risks or to rule them out for expected operating conditions for Operating Horizon studies.

1. If instability risks are identified, there is a need to establish Stability limits (which may include implementing Real-time Stability Limit calculators) and/or to establish Operating Plans to address those instability risks.
2. If instability risks are ruled out for expected operating conditions, then subsequent reliability analyses might exclude Stability analyses for the Operating Horizon, provided system conditions are comparable to those represented in prior studies.

If instability risks can be ruled out for expected operating conditions, then subsequent reliability analyses – i.e., Operational Planning Analyses (OPA) and Real-time Assessments (RTA) – using

<sup>18</sup> A BES bus that is serving load is the bus with direct transformation from BES-level voltage to distribution-level voltage that serves load.

<sup>19</sup> TPL-001-WECC-CRT-4 WR1.3, WR1.4 and WR 1.5

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steady-state Contingency analysis of actual or expected conditions, are sufficient to confirm that the system can be reliably operated within acceptable pre- and post- Contingency performance requirements with regard to Facility Ratings and System Voltage Limits.

### **Differing Objectives for System Stressing**

Transfer analyses that stress the power system are performed to determine the pre- and post-Contingency reliability issues that can be encountered as transfers increase into a load area or across a transmission interface. How far the system is stressed as part of transfer analyses depends on the purposes and objectives of the analysis.

If the purpose of the transfer analyses is to determine Transfer Capability (TC) or TTC, the system generally needs to be stressed only to the point where a reliability limitation is encountered (with an applicable margin). In principle, TCs are generally determined by stressing the system until either of the following reliability constraints is encountered:


- In the pre-Contingency state, flows exceed normal Facility Ratings, voltages fall outside normal System Voltage Limits or instability occurs (i.e., the system is stressed to the point of unacceptable pre-Contingency performance regarding thermal, steady-state voltage or instability constraints).
- In the post-Contingency state, flows exceed emergency Facility Ratings, voltages fall outside emergency System Voltage Limits or instability occurs (i.e., the system is stressed to the point of unacceptable post-Contingency performance regarding thermal, steady-state voltage or instability constraints).

Most paths in WECC are either thermally limited or steady-state voltage limited, as opposed to transient stability or voltage stability limited. For these paths, transfer analyses have shown that the first reliability limitations encountered are post-Contingency exceedances of emergency Facility Ratings or emergency System Voltage Limits. For example, when stressing a path, transfer analyses indicate that at a certain level of transfer, a single Contingency, or a credible MC result in exceedance of another Facility's emergency Facility Rating. Similarly, these transfer analyses may indicate that at a certain level of transfer, single Contingency, or a credible MC result in voltage at a bus falling outside its emergency System Voltage Limit.

While TC studies do not require that the system be stressed appreciably beyond the point of encountering the first reliability limitation, the same cannot be said for transfer analyses that are performed for purposes of determining whether instability risks exist for expected system conditions. Because actions may be taken in the actual system conditions that mitigate thermal and voltage limitations identified as a first reliability limitation, it may be necessary to identify where subsequent operation may approach a point of instability.

To adequately determine whether instability risks exist for expected system conditions for a given transmission interface or load area, the system must be stressed beyond the point where thermal or voltage limitations are encountered. The question is: how far does the system need to be stressed before instability risks can be ruled out for all practical purposes?

Note that transfer analyses for purposes of determining TC or TTC are outside the scope of the SOL Methodology.

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### **Stressing Requirements to Determine Instability Risks**

Transient instability, voltage instability or Cascading may occur in response to a single Contingency or a credible MC under stressed conditions. Under this methodology, it is the primary responsibility of the TOP to identify or rule out instability risks and to determine how far transmission interfaces and load areas should be stressed to accomplish this intended objective. System stressing requirements depend on several factors and therefore cannot be specified in a one-size-fits-all approach. While the system should be stressed far enough to accomplish the intended objective, the expectation of this methodology is to stress the system up to – and slightly beyond – reasonable maximum stressed conditions. It is not the intent of this methodology for TOPs to stress the system unrealistically or to stress the system to levels appreciably beyond those that are practically or realistically achievable.

This methodology should be applied to applicable studies performed in the Operations Horizon including, at a minimum, seasonal studies and outage coordination studies as determined to be necessary by the TOP. While the stressing methodology may optionally be applied to Operational Planning Analyses and Real-time Assessments, it is not required. For transmission interfaces that span multiple TOP Areas, the TOPs that operate the Facilities on the interface are encouraged to coordinate to determine appropriate levels of stressing necessary to identify or rule out instability risks. TOPs are encouraged to document stressing levels performed in operations planning studies and to communicate these levels and the results of these analyses to the RC when instability or Cascading is identified. See Appendix D for recommended guidelines for performing the System Stressing Methodology.

The following considerations should be used as a guideline to determine appropriate levels of system stressing:

1. Source area is exhausted – When stressing a transmission interface, in some cases it is possible to maximize the source area in the simulation before any reliability issues (Facility Ratings, System Voltage Limits or instability) are encountered. If the source area is exhausted in simulations, then it can be concluded that there is no way to realistically simulate any additional transfers. Load should not be scaled unrealistically as part of increasing exports. For example, when simulating exports, it may be unreasonable to scale load down by 50 percent of its expected value to simulate exports. The TOP is encouraged to determine reasonable uses of load as a mechanism for simulating exports.
2. If the source is maximized before either the nose of a PV or VQ curve is reached, before transient instability occurs, or before Cascading takes place (per the Cascading test outlined in the SOL Methodology), then it can be concluded that no instability or Cascading risks practically exist for the interface and there is no reliability need to establish Stability limits for the interface or load area. Different methodologies will be used (as further discussed below) for transmission interfaces where source generation cannot be maximized in the simulation.
3. Sink area is depleted – When stressing an interface into a load area, it is possible to de-commit or reduce the output of all generators internal to the load area (i.e., serve the load with ~100 percent imports) before any pre- or post-Contingency reliability issues (Facility Ratings, System Voltage Limits or instability) are encountered. Entities should model the expected minimum generation commitment in the load sink area at the expected maximum import level

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and simulate the largest generation Contingency as part of simulations. If the generation internal to the sink load area is decreased to the minimum generation commitment level and the sink load is modeled at the expected maximum conditions, then it can be concluded that there is no practical way to simulate any additional imports into the area. Load should not be scaled unrealistically as part of increasing imports. For example, when simulating imports, it may be unreasonable to scale load in the sink area up by 150 percent of its expected value to simulate imports. The TOP is encouraged to determine reasonable uses of load as a mechanism for simulating imports.

4. If the generation internal to the sink load area is depleted and load is maximized either before the nose of a PV or VQ curve is reached, before transient instability occurs, or before Cascading takes place (per the Cascading test outlined in the SOL Methodology), then it can be concluded that no Stability Limits or Cascading risks practically exist for the load area and there is no reliability need to establish a Stability Limit for the load area.
5. It may be possible to simulate flow on an interface or into a load area to levels that are unrealistic for operations. While it is encouraged that the system be stressed beyond the historical 2.5-to-5 percent levels for identifying or ruling out instability risks, the TOP, in collaboration with neighboring TOPs as necessary, are encouraged to determine reasonable maximum stressing conditions to identify or rule out instability risks. If the system is stressed to levels just beyond those determined by impacted TOPs as being reasonably expected maximums and no instability occurs in the simulations, or simulated flows do not reach the level where potential Cascading can occur, then it can be concluded that no instability or Cascading risks practically exist for the interface or load area and thus there is no reliability need for establishing stability limits or stability-related Operating Plans.
6. It is possible to stress the system to a point where potential Cascading is encountered. Cascading tests should be performed consistent with the *Instability, Cascading, Uncontrolled Separation and IROLs* section of the SOL Methodology. This analysis assumes that pre- and post-Contingency flows are below applicable Facility Ratings prior to the transfer analysis.
7. System stressing studies may result in transient instability or the nose of a PV or VQ curve being reached<sup>20</sup> either under pre-Contingency conditions or upon occurrence of a single Contingency or credible MC. This condition indicates the presence of an instability risk and thus the need to establish a transient or voltage Stability Limit or to otherwise manage the instability risk via an Operating Plan.
8. Any instability or Cascading risks identified because of applying this system stressing methodology should be communicated to the RC. For identified Cascading or instability risks, the RC will collaborate with the TOP(s) in the establishment of Stability limits and Operating Plans to mitigate these risks.

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<sup>20</sup> If the nose is not reached and different solving techniques do not result in a solution, then the last solved solution determines the Stability Limit.

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## Appendix E: Interconnection Reliability Operating Limit (IROL)

When the SOL Methodology uses the term IROL, it is used in the context of the IROL being identified in studies performed one or more days prior to Real-time. Per the SOL Methodology, IROLs are always pre-identified through studies.

The RC is responsible for declaring IROLs. TOPs are not responsible for declaring IROLs; however, TOPs are responsible for communicating and collaborating with the RC when studies (seasonal studies, special studies, outage studies or OPAs) identify instability (whether contained or uncontained), Cascading or uncontrolled separation as described in the SOL Methodology. Upon this communication, the RC then collaborates with the TOP to determine if an IROL needs to be established to address these risks.

IROLs are established to prevent instability, uncontrolled separation or Cascading as described in the SOL Methodology for:

1. Single Contingencies and
2. Credible MCs.

For identification purposes, the following three study methodologies may be used to identify IROLs: Conditional IROLs; Planned Outage Condition (POC) IROLs; and Facility Rating-Based IROLs.


### **Conditional IROL Study Methodology**

Conditional IROLs are identified to prevent instability, uncontrolled separation or Cascading as described in the SOL Methodology for:

1. N-1-1 and N-1-2 operations starting with an “all transmission Facilities in service” case, with system adjustments.

Conditional IROLs are not effective under normal operating conditions (i.e., all critical transmission Facilities in service). Therefore, there is no mitigation required for the Conditional IROLs under normal operating conditions. Conditional IROLs will become effective only when the first critical Facility is out of service (planned or forced). Mitigation is required if any Conditional IROL is exceeded after the first critical Facility is out of service.

Conditional IROLs are identified through seasonal studies and through special studies conducted by the RC, by the TOP(s) or by the RC in collaboration with the TOP(s). However, it is the RC that declares IROLs for use in the Operations Horizon. Relevant information for IROL identification can be gleaned from several sources including, for example, prior operational experiences/events, planning studies performed in association with the NERC TPL standards, or corresponding requirements applicable to PCs and TPs in FAC-014-3.

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**Note:** Conditional IROLs are not required to be established, but if the RC and TOPs agree to perform the analysis, then the following “Conditional IROLs” sections provide guidance on what to consider for N-1-1 and N-1-2 conditions.

Application:

1. Addresses known N-1-1 and N-1-2 risks that could result in instability, Cascading or uncontrolled separation as described in the SOL Methodology
2. Applicable to an “all transmission Facilities in service” starting point case(s)
3. Addresses N-1-1 and N-1-2 operations (with system adjustments) where:
  - a. “N” is an “all transmission Facilities in service” case(s)
  - b. The first “-1” is a forced outage or a single Contingency event
  - c. The second “-1” is the next worst single Contingency, or the “-2” is the next worst MC
4. Conditional IROLs are not established for N-2-1, or N-2-2 conditions, due to the low probability of occurrence of the first “-2” Contingency event.

Purpose:


Conditional IROLs are intended to pre-identify and prepare for the following scenario:

1. The system is being operated in a “normal” mode. The system demonstrates acceptable system performance for the pre- and post-Contingency state.
2. A single Contingency or a forced/urgent outage of a single Facility occurs.
3. The system is now in a new and different state; system adjustments can be made.
4. Based on this new state, the next single Contingency or MC could result in instability, Cascading or uncontrolled separation as described in the SOL Methodology, and thus the system is now in an N-1 (or credible N-2) insecure state.

Rationale for Conditional IROLs:

Conditional IROLs can be identified and established to provide System Operators an awareness of instances where a single Contingency or a forced/urgent outage on a single Facility is pre-determined by studies to render the system in a state where the next single Contingency or Always Credible MC can result in instability, uncontrolled separation or Cascading as described in the SOL Methodology.

1. Given an initial condition state of “all transmission Facilities in service” in a normal mode of operation, if a single Contingency or a forced/urgent single Facility outage causes engineers/operators to re-position the system with the specific objective of preventing instability, Cascading or uncontrolled separation as described in the SOL Methodology for the next worst single Contingency or Always Credible MC, then the system is in an N-1 or N-2 insecure state until those system adjustments can be made to transition the system

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to an N-1 or N-2 secure state.

2. When N-1-1 or N-1-2 studies indicate that the first “-1” renders the system in an N-1 or N-2 insecure state where the next single Contingency or Always Credible MC can result in instability, Cascading or uncontrolled separation as described in the SOL Methodology, a Conditional IROL can be identified. This IROL would become effective when the first “-1” event occurs and would prevent the next single Contingency or Always Credible MC from resulting in instability, Cascading or uncontrolled separation as described in the SOL Methodology. Such IROLs will be in effect only upon a forced/urgent outage or Contingency of the first “-1” Facility.
3. For such predetermined N-1-1 and N-1-2 Conditional IROLs, it is acceptable to operate the system such that the first “-1” Contingency will result in exceeding the IROL, provided that System Operators know that they are able to mitigate the IROL within the IROL  $T_v$  after the “-1” Contingency event occurs. If System Operators are not able to mitigate the IROL exceedance within the IROL  $T_v$  after the first “-1” Contingency event occurs, then pre-Contingency actions must be taken such that System Operators are able to mitigate the IROL exceedance within the IROL  $T_v$  after the first “-1” Contingency occurs<sup>1</sup>.

Process for Identifying Conditional IROLs:

Conditional IROLs are identified using transient analysis and/or post- transient analysis techniques. The following analysis process should be used to determine if an N-1-1 or an N-1-2 IROL should be identified:

1. N-1-1 and N-1-2 analysis assumes an “all transmission Facilities in service” initial condition. Assessments are based on reasonable max stressing conditions and historical flows. Reference the system stressing methodology.
2. The first single Contingency is simulated.
3. No system adjustments are made other than allowable automatic action such as governor response, automatic capacitor switching, RAS, etc.
4. The next worst single Contingency or Always Credible MC is then simulated to determine if the Contingency results in instability, Cascading or uncontrolled separation as described in the SOL Methodology. The analysis of this next worst single Contingency or Always Credible MC event should account for allowable automatic schemes that are designed to address these Contingencies.
5. If the next single Contingency or Always Credible MC results in instability, Cascading or uncontrolled separation as described in the SOL Methodology, then the condition indicates that system adjustments must be made after the first “-1” Contingency, but before the second Contingency, to prevent the instability, Cascading or uncontrolled separation as described in the SOL Methodology from occurring. This fact points to the presence of an IROL that would become effective upon a forced/urgent outage or Contingency of the first “-1” Facility.

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6. Once these risks are identified, the N-1-1 and N-1-2 studies should then identify system adjustments that must be made (and the timing associated with these adjustments) after the first “-1” Contingency event to prevent the second Contingency event from resulting in instability, Cascading or uncontrolled separation as described in the SOL Methodology. These system adjustments should be taken into consideration when developing the IROL Operating Plan. IROLs must be determined that can be applied upon a forced/urgent outage or a Contingency of the first “-1” Facility. These IROLs can be pre-established values, or they can be calculated in Real-time.
7. The lower of the relay setting or 125 percent Cascading test as described in the SOL Methodology applies for the determination of Cascading.
8. For identified IROLs for N-1-1 and N-1-2 conditions, Real-time N-1-1 and N-1-2 analyses/calculations are prudent to provide System Operators awareness as to whether that IROL would be expected to be exceeded upon a Contingency or a forced/urgent outage of the first “N-1” Facility.


Conditional IROL Example:

Studies show that the loss of Facility X is expected to render the system in a position where a subsequent Contingency on Facility Y would result in wide-area voltage instability, i.e., that the loss of line X would render the system in an N-1 insecure state for Contingency Y. A Conditional IROL is identified to prevent the loss of Facility X, followed by a Contingency of Facility Y, resulting in wide-area voltage instability.

1. The Conditional IROL is identified on the monitored interface appropriate for determining wide-area voltage instability for the loss of Facility Y.
2. For this example, the Conditional IROL is monitored as the maximum MW flow (the last good solution) on the monitored interface above which the subsequent loss of Facility Y results in wide-area voltage instability.
3. The Conditional IROL becomes effective when Facility X experiences a forced/urgent outage. The Conditional IROL is not in effect unless there is a forced/urgent outage or Contingency of Facility X.
4. The IROL is exceeded when Facility X experiences a forced/urgent outage, and subsequent Real-time Assessments indicate that the flow on the monitored interface is above the value where the loss of Facility Y results in wide-area voltage instability. The IROL can be a pre-established value, or it can be calculated in Real-time.

**POC IROL Study Methodology**

IROLs can be identified during planned outage conditions (POC). POC IROLs are temporary in nature and do not apply when the planned outage is not in effect. Additionally, POC IROLs are identified for the outage conditions as expected system conditions warrant. For example, a planned outage for Facility XYZ during the month of August when loads are high may require a POC IROL to be identified for the duration of that outage; however, an outage on that same Facility in November when loads are

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low may not require a POC IROL to be identified.

POC IROLs are generally not identified to address N-1-1 or N-1-2 operations during planned outages; however, TOPs and the RC may determine that it is prudent to identify an N-1-1 or an N-1-2 POC IROL for long-duration outages (such as those that are in effect for an entire season) where the TOP and the RC collaboratively determine that there is a high risk for N-1-1 or N-1-2 instability risks while the outage is in effect.

### Identifying POC IROLs


When transmission or generation outages are planned, the system must be studied to determine if the planned outage created any new instability risks that otherwise would not practically exist. When the system is operated in a “normal” mode, many types of limitations exist – Facility Ratings, System Voltage Limits or Stability. In “normal” mode, the system can support transfers throughout the various seasons that are well understood. When planned outages are brought into the equation, the system may not be able to support the transfer levels that it otherwise would be able to support.

Per the IRO-017 Outage Coordination process, BAs, TOPs, and the RC are expected to perform studies/assessments to ensure that the BES will be in a reliable pre- and post-Contingency state while an outage is in effect. Acceptable system performance as described in the SOL Methodology is required while planned outages are implemented.

It is not the intent of the IRO-017 Outage Coordination Process or the SOL Methodology to be highly prescriptive for study/assessment requirements related to planned outages. TOPs are responsible for determining the level of study needed to achieve acceptable pre- and post-Contingency system performance while the outage is implemented. The level of complexity of TOP studies/assessments will vary depending on the type and number of simultaneous outages and on the unique challenges and reliability issues posed by the outages. It is left to the judgment of the TOP to determine what level of analysis is appropriate for a given planned outage situation. TOPs are responsible for determining how far to stress their system to identify or rule out instability risks for the planned outage conditions. When determining how far to stress the system during planned outage conditions, TOPs should follow the guidance provided in the *System Stressing Methodology* in Appendix D of the SOL Methodology.

While many planned outages require the development and implementation of outage specific Operating Plans to facilitate a given planned outage, some outages may also require the development of an IROL to facilitate the outage.

When planned outage studies indicate that, at reasonable and realistic maximum stressed conditions during the planned outage(s), a single Contingency or a credible MC results in instability, Cascading or uncontrolled separation as described in the SOL Methodology, an IROL is warranted to be identified for that planned outage.

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### **Facility Rating-Based IROL Study Methodology**


Facility Rating-based IROLs are identified when studies show that a Contingency results in excessive loading on a Facility, which triggers a chain reaction of Facility disconnections by relay action, equipment failure or forced immediate manual disconnection of the Facility (for example, due to line sag or public safety concerns), consistent with the NERC definition of Cascading. The Cascading test is used to determine Cascading based on available Facility Ratings. Facility Rating-based IROLs prevent non-stability related Cascading due to excessive post-Contingency loading of Facilities. While such IROLs may be established as Conditional IROLs for N-1-1 or N-1-2 operations, they may also be established for credible MCs, or planned outage conditions to address the next worst single Contingency or the next worst credible MC.

For Facility Rating-based IROLs, the IROL will be identified on the initial excessively loaded Facility that is expected to be disconnected by automatic or manual action, leading to Cascading. The IROL value will be the lesser of the relay trip setting or 125 percent of the Emergency Rating. These IROLs will be monitored for their performance in the post-Contingency state through RTAs.

#### **Facility Rating-Based IROLs - Credible MC (Example 1):**

Studies show that credible MC X results in Facility Z loading up to or beyond the lower of the relay trip setting or 125 percent of its Emergency Rating. Cascading tests indicate that the MC X would result in Cascading. An IROL is established to prevent MC X from resulting in Cascading.

1. The Facility Rating-Based IROL is identified when it becomes a risk to reliability. For planned outage conditions, the IROL may be in effect during the planned outage. Otherwise, the IROL may need to always be in effect.
2. The Facility Rating-Based IROL is identified on the initial excessively loaded Facility that is expected to be disconnected by automatic or manual action, leading to Cascading. Accordingly, the IROL is the MVA or Amp value on Facility Z that results exceeding the lower of the Facility Z's trip setting or 125 percent of its highest applicable Emergency Rating.
3. The Facility Rating-Based IROL is monitored as the calculated post-Contingency flow on Facility Z in response to MC X.
4. The Facility Rating-Based IROL is exceeded when Real-time Assessments indicate that MC X results in flow on Facility Z exceeding the lower of its trip setting or 125 percent of its highest applicable Emergency Rating.

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Conditional Facility Rating Based IROL (Example 2):


“All transmission Facilities in service” studies show that the loss of Facility X is expected to render the system in a position where a subsequent Contingency on Facility Y would result in Facility Z loading up to or beyond the lower of the Facility trip setting or 125 percent of its highest applicable Emergency Rating. Cascading tests indicate that the loss of Facility X followed by a subsequent Contingency on Facility Y (with no system adjustments between Contingencies) would result in Cascading, i.e., that the loss of line X would render the system in an insecure state for single Contingency Y. An IROL is identified to prevent the loss of Facility X, followed by a Contingency of Facility Y, from resulting in Cascading.

1. The Conditional Facility Rating-Based IROL is identified on the initial excessively loaded Facility that is expected to be disconnected by automatic or manual action, leading to Cascading. Accordingly, the IROL is the MVA or Amp value on Facility Z that results in its tripping, in this case it is 125 percent of its highest applicable Emergency Rating.
2. The Conditional Facility Rating-Based IROL is monitored as the calculated post-Contingency flow on Facility Z for the loss of Facility Y.
3. The Conditional Facility Rating-Based IROL is not in effect unless there is a forced/urgent outage or Contingency of Facility X. The IROL becomes effective when Facility X experiences a forced/urgent outage.
4. The IROL is exceeded when there is a forced/urgent outage on Facility X, and subsequent Real-time Assessments indicate that a Contingency of Facility Y results in flow on Facility Z exceeding the lower of its relay trip setting or 125 percent of its highest applicable Emergency Rating.

**IROLs and Risk Management for Local and Contained Instability**

When IROLs are established, the current set of NERC Reliability Standards require that System Operators take action up to and including shedding load to prevent exceeding that IROL. There may be planned or forced outage scenarios where the system is vulnerable to localized, contained instability. In prior outage scenarios where there are local, contained instability impacts, the severity and extent of the instability impact may represent an acceptable level of risk that may not warrant extreme operator action such as pre-Contingency load shedding to prevent the instability from occurring in response to a Contingency event.

When such scenarios are determined to represent an acceptable level of risk, the local contained instability risk may be managed via an Operating Plan that does not include the use of an IROL and does not include pre-Contingency load shedding.

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Possible Process for Determining Acceptable Levels of Risk for IROL Determination

When prior outage studies indicate that a localized, contained area of the power system is at risk of instability in response to the next worst single Contingency or credible MC:

1. TOPs determine the mitigations and a corresponding Stability Limit that would be required to prevent that Contingency from resulting in localized, contained instability. The Stability Limit would be expressed as a maximum flow value on a monitored interface, cut plane, or import bubble for the conditions under study.
2. When studies indicate that all other mitigations have been exhausted and pre-Contingency load shedding is the only option remaining to prevent the Contingency from resulting in localized, contained instability, TOPs should determine the amount and location of load that must be shed pre-Contingency (at peak load for the period under study) to prevent the Contingency from resulting in localized, contained instability.
3. TOPs determine the amount of load (at peak for the period under study) that is at risk of being lost due to instability in response to the Contingency. This assessment should include a determination of the physical and electrical extent of expected instability (e.g., the specific station buses that are expected to experience voltage instability, the expected voltage levels at adjacent stations that represent the boundary of impact). The assessment should also include any relay action that is expected to occur that might isolate that area of impact.
4. If the amount of pre-Contingency load shedding required to prevent the Contingency from resulting in localized, contained instability (as determined in Item 2) is relatively high compared to the amount of load that is at risk due to instability (as determined in Item 3), then the TOP collaborates with the RC to determine the levels of acceptable risk and to create an Operating Plan that addresses the instability risk commensurate with those decisions. Accordingly, the Operating Plan might not include steps for pre-Contingency load shedding, depending on the risk management issues at hand. A key objective is to ensure that the mitigations prescribed in the Operating Plan are consistent with good utility practice.
5. If it is determined that the localized, contained instability represents an unacceptable level of risk, and pre-Contingency load shedding is warranted to prevent the Contingency from resulting in the local, contained instability, then an IROL should be established by the RC to prevent the Contingency from resulting in the localized, contained instability. In such scenarios, the IROL will be based on the Stability Limit determined in Item 1, and the IROL Operating Plan will be based on the information determined in Item 2.