RELIABILITY COORDINATOR AREA SYSTEM OPERATING LIMIT METHODOLOGY

By SPP Operations Staff

Effective Date: 6/1/2022

Version 1.2

REVISION HISTORY

DATE OR VERSION NUMBER	PUBLISHED DATE	Effective Date	CHANGE DESCRIPTION
1.0	10/19/2018		Initial Creation with the Approval of RR309
1.1	9/2/2021	10/1/2021	Update generator contingency definition to remove 150 MW generator threshold.
1.2	04/07/2022	6/1/2022	Addition of an Introduction, addition of Section - Instability, Cascading, Uncontrolled Separation and IROLs, IROL establishment, & SPP RC Roles and Responsibilities sections (all sections to address compliance obligations). Added an effective date column to the revision history.

CONTENTS

1. INTRODUCTION

This document is SPP's 'System Operating Limits Methodology for the Operations Horizon' for the Eastern Interconnection [NERC Standard FAC-011]. This document establishes the methodology for use in the SPP RC Area - Eastern Interconnection for developing System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) for use in the Operations Horizon pursuant to NERC Reliability Standards FAC-011 and FAC-014.

All requirements for establishing SOLs and IROLs are contained in the body of this document. An additional document titled 'Appendices to Reliability Coordinator Area System Operating Limit Methodology Eastern Interconnection' provides best practices or background information but does not contain additional NERC requirements.

TOPs and the RC 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 Outage Coordination Process, followed by Operational Planning Analyses (OPAs), and ultimately 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].

1.1 METHODOLOGY FOR THE DETERMINATION OF OPERATING HORIZON SOLS

SPP's Methodology designates System Operating Limits (SOLs) in the Operating Horizon to consist of defined Flowgate limits, limits defined in operating guides, and limits designated by agreement between the RC and TOP to prevent other reliability concerns such as instability. SPP respects all BES Facility Ratings in both Real-Time Assessments and through Operational Planning Analysis. SPP primarily controls the BES using both permanent and temporary Flowgates per defined congestion management processes. SPP also controls the BES using coordinated operating plans or operator actions in specific situations in the absence of a Flowgate. During the time a Flowgate or an operating guide is being created, SPP shall issue Operating Instructions to implement manual actions as deemed necessary by the Reliability Coordinator to control the BES and operate within SOLs.

1) TOPs shall develop, at minimum, SOLs that respect all BES Facility Ratings in

coordination with the SPP RC. In addition, SOLs may be developed based on other operating criteria.

2) SOLs shall not exceed Facility Ratings. SOLs equal applicable Facility Ratings unless additional studies have established a lower limit based on other operational issues such as transient, dynamic and voltage stability, etc. The Facility Ratings used in the Operating Horizon or Real-Time Horizon may be higher or lower than the Facility Ratings used in the Planning Horizon. All Facility Ratings shall be calculated in accordance with the appropriate Transmission Owner's Facility Rating methodology. Ratings that have been adjusted must be coordinated so that the impacted operating entities are aware of the duration that the adjusted rating may be used.

3) Including anticipated system topology, generation dispatch, and load levels, SOLs shall be determined per this SOL methodology and based on results of system studies as described below.

4) Pre-contingency and first contingency studies will be conducted to identify potential SOL exceedances for current and next day.

5) Voltage stability and angular stability issues are studied as deemed necessary by operator and engineer experience and engineering judgment to identify stability SOLs.

6) As deemed necessary by study results, an operating guide to aid operators in mitigating potential SOL exceedances may be produced. These guides may be temporary or permanent, depending whether the potential SOL exceedance is due to a short-term outage, seasonal loading issues, etc. At a minimum, this operating guide will include:

    a. Statement of type(s) of potential SOL exceedances revealed by study (voltage/thermal/stability)

    b. Applicable dates

    c. Available/recommended mitigation methods, including generation redispatch (maximum MW and/or minimum Mvar generation), transmission reconfiguration, reclosing reconfiguration, load shedding, and Transmission Loading Relief (TLR).

7) Identified SOLs are screened to compile a list of potential IROLs per the following criteria:

    a. Potential IROLs will be investigated when a contingency analysis highlights a thermal overload in excess of 120% of the SOL of the monitored Facility.

    b. Potential IROLs will also be investigated when a contingency analysis

highlights an under-voltage condition characterized by bus voltages of less than 90% across three or more BES Facilities. The potential IROL condition will be reviewed further by evaluating the system response to the loss of the Facility with the SOL expected to be exceeded. The original potential IROL condition will be assumed to be a confirmed IROL condition if the evaluation reveals that the ensuing loss of the Facility with the SOL exceedance results in another BES Facility being overloaded to greater than 120% of its SOL or three or more additional BES Facilities with bus voltages in the area experiencing projected post-contingency voltages less than 90% of nominal voltage, unless there are studies or system knowledge that the SOL is not an IROL.

8) The IROL TV is 30 minutes unless studies dictate a shorter time.

9) Remedial Action Schemes (RAS's) are allowed to prevent prolonged undervoltage and to preserve system voltage and machine stability.

1.2 SOL PROVISIONS

1) In the pre-contingency state, the BES shall demonstrate transient, dynamic, and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage, and stability limits. In determining SOLs, the BES condition used shall reflect future system conditions with all Facilities operated in their normal operating condition.

2) Following single contingencies as defined in (a), (b), and (c) below, the system shall demonstrate transient, dynamic, and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage, and stability limits; and Cascading Outages or uncontrolled separation shall not occur.

    a. Single-line-to-ground or three-phase fault (whichever is more severe), with normal clearing, on any faulted generator, line, transformer, or shunt device.

    b. Loss of any generator, line, transformer, or shunt device without a Fault.

    c. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

3) In determining the system's response to a single Contingency starting with all Facilities operated in their normal operating condition, the following shall be acceptable:

a. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area. System reconfiguration should be implemented to minimize the interruption of electric supply to the extent possible.

b. System reconfiguration through manual or automatic control or protection actions.

4) To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.

5) Starting with all Facilities operated in their normal operating condition and following any of the multiple contingencies identified in Reliability Standard TPL-001 the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

6) In determining the applicable multiple contingencies identified by the Planning Coordinator, in addition to the actions identified in 3(a) and 3(b) above, the following shall be acceptable:

a. Planned or controlled interruption of electric supply to customers (load shedding) the planned removal from service of certain generators, and/or curtailment of contracted firm electric power transfers. System reconfiguration should be implemented to minimize the interruption of electric supply to the extent possible.

1.3 SYSTEM MODELING AND CONTINGENCY DEFINITION

1) All offline models shall be based on a coordinated model of the Eastern Interconnect and any necessary Facilities in other Interconnections. The model shall include all Transmission Operator (TOP) Areas within the SPP RC footprint as well as Facilities in adjacent TOP Areas that have been determined to have impact on the SPP RC footprint.

2) The model shall include all non-radial Facilities within the BES. Loads served over radial lines may be modeled as aggregate at the delivery bus. Distribution capacitors can be modeled as aggregate at a load bus.

3) The online model used by the SPP EMS application is constructed from data in the offline model (PSS/E).

4) At a minimum the contingency list used in the operating horizon shall include all non- radial BES transmission lines and transformers and all BES generating resource(s). Additional contingencies will be included as provided by other applicable registered entities.

2. INSTABILITY, UNCONTROLLED SEPARATION, CASCADING, AND IROLS

2.1 INSTABILITY

An IROL, as defined by NERC, is an SOL that, if exceeded, could result in instability.

There are many forms of instability, each with a wide spectrum of reliability impacts –from minimal impact, such as losing a unit due to "instability," to major and devastating impact, such as losing a significant portion of the BES due to instability.

It is recognized that not all instability events pose the same degree of risk to the reliability of the BES. However, it is critical that studies/assessment determine how – or if – the instability would be contained, and to understand the impact that the instability may have on the BES.

Accordingly, if a transient or voltage instability event has demonstrated through studies to have wide-area BES impact, then the establishment of an IROL may be warranted.

2.2 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.

2.3 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.

Cascading test – If powerflow studies indicate that the successive tripping of Facilities stops before the case diverges, then by definition, 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. Valid cascading events identified in real-time are assessed for potential IROL establishment.

2.3.1 POWERFLOW CASCADING TEST:

A. Run Contingency analysis and flag Contingencies that result in post-Contingency loading in excess of the lower of:
    a. The Facility(ies)'s trip setting
    b. 120 percent of the highest Emergency Rating
B. For each flagged Contingency, open the contingent element(s) that cause(s) the post- Contingency loading and all subsequent Facilities that overload in excess of (1) (a) or (b) above. Run powerflow without simulating any manual system adjustments.
C. Repeat step (2) for any newly overloaded Facility (ies) in excess of (1) (a) or (b) above. Continue with this process until no more Facilities are removed from service or until the powerflow solution diverges.
D. 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 120 percent of the highest Emergency Rating, then further investigation into post-Contingency

loading may occur (if time allows) before declaring that Cascading occurs.

3. IROL ESTABLISHMENT

Interconnection Reliability Operating Limits (IROLs) are a subset of the SOLs that, if violated, could lead to instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the Bulk Electric System.

IROLs are identified through engineering studies and analysis utilizing seasonal studies, OPAs or other offline studies. Additionally, identified SOLs are screened in the Operations Planning horizon and investigated when a real-time contingency analysis indicates a

- thermal overload in excess of 120% of the SOL of the monitored facility or,
- valid unsolved or valid non-converged contingency.

This condition will be reviewed further by evaluating the system response to the loss of the SOL violated facility. An IROL will be established if the evaluation reveals that the ensuing SOL violated facility may cause instability, uncontrolled separation, or cascading.

3.1 MANAGING IROL EXCEEDANCES

The RC is responsible for declaring IROLs. 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. Upon this communication, the RC then collaborates with the TOPs to determine if an IROL needs to be established to address these risks.

In the event of an IROL violation, the Bulk Electric System is vulnerable to instability, uncontrolled separation, and/or widespread cascading outages. All efforts, up to and including shedding of firm load, shall be made to reduce the flow below the IROL limit within 30 minutes. In order to be best prepared for this situation, SPP has created relief guides that will assist the Reliability Coordinator in the relief of any flowgate with an IROL.

IROL limits are only applicable in the forward direction of flowgate unless specifically stated in an IROL relief guide.

4. SPP RC ROLES AND RESPONSIBILITIES

4.1 ADHERENCE TO 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. SPP RC performs the following functions to meet this requirement [NERC Standard FAC-014]:

A. SPP RC ensures that Facilities in SPP's network model reflect the Facility Ratings as established by the TOs and provided to SPP by the TOs/TOPs, consistent with this SOL Methodology.

B. SPP RC performs a coordination and facilitation role in the seasonal planning process for its RC Area as needed. See Appendix E, Recommended Seasonal Operations Planning Coordination Process.

C. SPP RC ensures that during the determination of SOLs, the BES condition used reflects current or expected system conditions and reflects changes to system topology such as Facility outages.

D. SPP RC ensures that buses in the network model are associated with the System Voltage Limits as provided by TOPs, consistent with this SOL Methodology.

E. SPP RC reviews the Stability limits provided by TOPs to ensure they are established consistent with this SOL Methodology. SPP RC makes a final determination whether the Stability limits are declared an IROL.

F. SPP RC ensures RC System Operators and engineers have awareness of identified Stability limits and IROLs.

G. When assessments indicate that the system is at risk of instability, uncontrolled separation, or Cascading for the next contingency, the RC is expected to bring the system to a secure state with no intentional delay as it would address an IROL utilizing the applicable Operating Plans.

H. SPP RC'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. SPP RC shall post its RTCA results in a format that is mutually agreed upon by the SPP RC and SPP RC Area TOPs.

I. SPP RC utilizes a real-time voltage stability analysis tool and communicates the results of this

tool to impacted TOPs.