Master/Local Control Center Procedure No. 15

(M/LCC 15)

System Operating Limits Methodology

1. References

NERC FAC Standards – Facilities Design, Connections, and Maintenance Standards: System Operating Limits Methodology for the Planning/Operations Horizon

NERC TPL, TOP and IRO Standards - Transmission Planning, Transmission Operations and Interconnection Reliability Operations and Coordination Standards

NERC MOD Standards - Modeling, Data, and Analysis Standards

NERC Reliability Standard VAR-001 - Voltage and Reactive Control

NPCC Regional Reliability Reference Directory #1 Design and Operation of the Bulk Power System

ISO New England Transmission Operating Guide, Procedure to Protect for Loss of Single Source Contingency Guide - Text Document

ISO New England Operating Procedure No. 1 - Central Dispatch Operating Responsibilities and Authority (OP-1)

ISO New England Operating Procedure No. 3 - Transmission Outage Scheduling (OP-3)

ISO New England Operating Procedure No. 8 - Operating Reserve and Regulation (OP-8)

ISO New England Operating Procedure No. 12 - Voltage and Reactive Control (OP-12)

ISO New England Operating Procedure No. 12 - Voltage and Reactive Control - Appendix B - Voltage & Reactive Schedules (OP-12B)

ISO New England Operating Procedure No. 14 - Technical Requirements for Generators, Demand Response Resources, Asset Related Demands and Alternative Technology Regulation Resources (OP-14)

ISO New England Operating Procedure No. 16 - Transmission System Data (OP-16)

ISO New England Operating Procedure No. 19 - Transmission Operations (OP-19)

ISO New England Operating Procedure No. 24 - Protection Outages, Settings and Coordination (OP-24)

ISO New England Planning Procedure No. 3 - Reliability Standards for the New England Area Pool Transmission Facilities (PP 3)

Master Local Control Center Procedure No. 7 - Processing Outage Applications, Attachment D – Minimum Advance Notice Times – Outage Requests for Specific Equipment (M/LCC7D)

2. Background

The purpose of this Master/Local Control Center (M/LCC) Procedure is to describe the reliability methodology developed and used by ISO New England (ISO) and Local Control Centers (LCCs) for operational planning and Real-Time operations of the New England Transmission System[1],in accordance with North American Electric Reliability Corporation (NERC) Reliability Standard FAC-010 System Operating Limits Methodology for the Planning Horizon, FAC-011 System Operating Limits Methodology for the Operations Horizon and FAC-014 Establish and Communicate System Operating Limits. Prescribed operator actions are further detailed in ISO Operating Procedure No. 19 - Transmission Operations (OP-19) and in several ISO Transmission Operating Guides (TOGs), ISO System Operating Procedures (SOPs), and Master/Local Control Center (M/LCC) Procedures.

NERC Reliability Standards and NPCC Directories and Criteria documents define specific requirements applicable to the design, planning and operation of the New England Transmission System. The provisions in this document and in OP-19 are used to determine the data and methodology used by ISO for the development of System Operating Limits (SOLs), and the subset of SOLs classified as Interconnection Reliability Operating Limits (IROLs) that are used for the operational planning and Real-Time operation of the New England Transmission System.

3. Responsibilities

ISO is responsible for performing the Reliability Coordinator (RC), Transmission Operator (TOP), and the Balancing Authority (BA) functions for the New England Transmission System. LCCs are responsible for performing the TOP function for their local areas. ISO and the LCCs are responsible for identifying SOLs. ISO is responsible for identifying the subset of SOLs that qualify as IROLs.

ISO and the LCCs are responsible for ensuring their respective network models use the same facility ratings as recorded in the NX-9 Transmission Information database unless temporary ratings have been implemented or the NX-9 data has been determined to be erroneous; in this case, the NX-9 data shall be updated as soon as possible.

ISO and the LCCs are responsible for ensuring that their respective network models use the same generator technical characteristics as recorded in the NX-12 Generator Technical Data in the Customer Asset Management System (CAMS) database.

ISO and the LCCs coordinate to monitor system loading and the status of applicable elements of the New England Transmission System that could result in SOL or IROL exceedances or that are, or could be, critical to SOLs and IROLs within the New England

[1] The New England Transmission System is defined in the ISO Tariff and includes the Reliability Coordinator Area/Balancing Authority Area (RCA/BAA), Bulk Electric System and bulk power system elements found within New England on the transmission network.

Transmission System. Such monitoring allows ISO and the LCCs to know the current status of all facilities whose failure, degradation or disconnection could result in an SOL or IROL exceedance.

ISO has clear decision-making authority, action plans, and agreements in place to immediately take actions, or to direct LCCs and Market Participants (MPs) within the New England Transmission System to take actions, to preserve the integrity and reliability of the New England Transmission System and the Interconnection. ISO and the LCCs operate the New England Transmission System to protect against instability, uncontrolled separation, or cascading outages from single-element contingencies and specified multiple-element contingencies. Information concerning these contingencies and how ISO respects the transmission system limits associated with these contingencies in system operations is contained within OP-19 and this Procedure.

ISO and the LCCs are jointly responsible for monitoring and mitigating SOLs and IROLs in Real-Time. In instances where there is a difference in derived limits, ISO requires that the LCCs, TOPs and MPs operate the New England Transmission System to the most conservative limit.

In operating the New England Transmission System, ISO makes every effort to have the New England Transmission System remain connected to the Eastern Interconnection. However, if ISO determines that by remaining interconnected, ISO is in imminent danger of exceeding an IROL, ISO will take actions or direct actions to protect the New England Transmission System.

This Procedure requires ISO to discuss options to mitigate potential or actual IROL exceedance with other affected RCs and to take actions, as necessary, to act in the best interests of the Interconnection at all times. ISO informs potentially affected LCCs and RCs of Real-Time or anticipated EMERGENCY System Conditions, discusses options, decides upon solutions to prevent or resolve the identified problem and takes actions to avoid, when possible, or mitigate the problem. ISO also requires that system protection is coordinated among operating entities. When ISO is notified of a relay or equipment degradation or outage that reduces system reliability, ISO takes corrective action, or directs the LCCs to take corrective action, as soon as possible.

If in operating the New England Transmission System, ISO or an LCC enter an unknown operating state (i.e., any state for which valid operating limits have **not** been determined), they will restore operations to respect limits within 30 minutes. Examples of unknown operating states, and remediation actions, include but are **not** limited to:

- When a defined interface has a voltage/stability limit for one or more elements out-of-service and then an additional line on the specified interface is removed from service, the present voltage/stability limit is unknown. The ISO on-call engineer will be notified as soon as reasonably possible and will promptly provide a revised voltage/stability limit for the applicable interface, all preferably within the first five minutes of entering an unknown operating state.

- When a defined interface has a voltage/stability limit for one or more elements out-of-service and then the limiting contingency for which the interface limit is based occurs, the present voltage/stability limit is unknown. The ISO on-call engineer will be notified as soon as reasonably possible and will promptly provide a revised voltage/stability limit for the applicable interface, all preferably within the first five minutes of entering an unknown operating state.

4. Network Model and Inputs

4.1 Network Model

The ISO network model used in the Real-Time operations horizon is contained in the ISO Energy Management System (EMS) and includes all Resources and transmission facilities in the New England Transmission System and an equivalence model for other 69 kV and radial 115 kV facilities within New England. In addition, ISO models all key Resources and transmission above 230 kV as well as an equivalence model for the 115 kV and 138 kV in both the neighboring RCAs of New Brunswick and New York. The Quebec transmission system is asynchronously interconnected to New England via HVDC and is therefore **not** explicitly modeled; instead, it is modeled as Resource or load.

For the operational planning horizon, transient stability, dynamic stability and voltage stability analysis, ISO uses an off-line network study model contained in the Siemens Power Technology International (PTI) Power System Simulator for Engineering (PSS/E) to identify those contingencies that may be identified as an SOL or IROL. This off-line network model originates from the NERC Multiregional Modeling Working Group (MMWG) series of network models. The level of modeling detail meets or exceeds the NERC MMWG modeling requirements and the requirements of NERC Modeling Standards.

For Real-Time and near Real-Time thermal and voltage analysis, the EMS network model Powerflow is used. This model includes the applicable approved transmission outages, Resource outages, load forecast, estimated external transaction schedules and Resource schedule. ISO also uses the EMS applications including Study-time Contingency Analysis (STCA), Real-Time Contingency Analysis (RTCA) and the Interface Limit Calculator (ILC) to model all identified contingencies. The ISO network model also includes the modeling and operation of approved Remedial Action Schemes (RASs) and Automatic Control Schemes (ACSs), where appropriate. The network model data and inputs System Operators use to perform Real-Time Assessments (RTA) are identified in Attachment L – Real-Time Assessment Data.

4.2 Transmission Facility Ratings

The foundation of the process for calculating thermal- or voltage-based SOLs is the establishment of a comprehensive model of the facilities comprising the New England Transmission System and adjacent AC systems. Transmission facility ratings are the foundation for the calculation of thermal-or voltage-based SOLs.

Transmission facility ratings are required to be supplied to ISO by the Transmission Owners (TOs) per ISO New England Operating Procedure No. 16 - Transmission System Data (OP-16) using the NX-9 data form. ISO administers an NX9 certification process that requires TOs to annually certify that all transmission equipment identified in

OP-16 is accurately represented on the appropriate NX-9 form. The NX-9 form contains data on the transmission element (transformer, line, reactor, capacitor, etc.) and the limiting component (relay, disconnect switch, etc.) as well as the Summer/Winter, Normal, Long-Time Emergency (LTE), Short-Time Emergency (STE) and Drastic Action Limit (DAL) ratings. The basis for the calculation of any SOL starts first with a comprehensive model of the facilities comprising the New England Transmission System and adjacent AC systems.

Either the TOs or LCCs provide voltage limits based upon facility ratings. The voltage limits include: Normal Voltage Limit (NORMVL), Long-Time Emergency Voltage Limit (LTEVL), Short-Time Emergency Voltage Limit (STEVL) and Drastic Action Voltage Limit (DAVL). High and low voltage limits are provided for NORMVL: both high and low voltage limits may not be declared for LTEVL, STEVL and DAVL. Voltage limits must be provided for all voltage levels monitored by the LCC (such as 345, 230, 115 and 69 kV) so that all stations with voltage monitoring may be checked for adherence to the voltage limits. The most limiting voltage limit will always be used where different voltage limits exist within a station or in adjacent stations. The voltage limits provided must exceed in-service BES under voltage relay settings.

4.3 Generator Technical Characteristics

The technical characteristics for Resources defined as Generators per ISO New England Operating Procedure No. 14 - Technical Requirements for Generators, Demand Response Resources, Asset Related Demands and Alternative Technology Regulation Resources (OP-14) are required to be supplied by the Designated Entity to ISO, using the NX-12 data form. The NX-12 form contains data on the technical characteristics of the Generator units (response rates, MW and MVAr operating limits, etc.) that will be used in the network model.

The Generator voltage schedules specified in ISO New England Operating Procedure No. 12 Voltage and Reactive Control (OP-12), Appendix B - Voltage and Reactive Schedules used in system operations and studies, are developed to meet SOLs and IROLs per the criteria and limits, as well as limiting contingencies, defined in OP-19 and its Appendices, and this Procedure and its Attachments.

5. Determining, Operating to and Communicating SOLs and IROLs

The SOL determination methodology requires that an SOL provides acceptable New England Transmission System performance, as described in OP-19. Consequently, the New England Transmission System is operated so that, in the pre-contingent state, it shall demonstrate transient, dynamic and voltage stability; all facilities shall be within their facility limits. The New England Transmission System shall continue to demonstrate transient, dynamic and voltage stability; all facilities shall be within their thermal, voltage and stability limits in the post-contingency state. The New England Transmission System operators (ISO and each LCC) determine SOLs. In the ISO and LCC determination of an SOL, the New England Transmission System conditions shall reflect current or expected system conditions, changes to system topology such as facility outages (including outages of protection systems) and facility de-ratings. ISO will commit and dispatch Resources, if available, in order to meet N-1 contingency coverage for an SOL, and N-1-1 coverage for an IROL. For SOLs, the impacted LCC(s) shall have the responsibility to identify if there is a need for post N-1 and/or pre N-1-1 firm load shedding. The impacted LCC(s) shall have the responsibility to determine the appropriate action plan to mitigate the firm load-shedding needed. The mitigation may include commitment and dispatch of Resources, an enhanced limit or a post-contingent action plan.

In the NERC Reliability Standards for Interconnection Reliability Operations and Coordination (IRO) it is stated that, for any identified IROL that is exceeded, the RC in conjunction with the TOP and BA will return its transmission system within the IROL limit. These actions shall be taken without delay, but **no** longer than 30 minutes. The criteria time limit in New England shall be 30 minutes to mitigate all IROL exceedances.

An SOL will normally be cleared within a two-hour period from the time of identification in contingency analysis or ILC. For an SOL, ISO and any impacted LCC will prepare and implement mitigation measures within the applicable time period after identification. These measures may include, but are **not** limited to, dispatch of Resources, facility switching and/or the application of enhanced thermal or voltage limits.

An SOL experienced in Real-Time needs immediate resolution; the applicable time T_V depends on the applicable limit, thermal or voltage, and may be shorter than two hours. Voltage SOLs have time limits, determined by the applicable LCC, as stated in MLCC 15 Attachment H and OP-19 Appendix K - Operating Voltage Limits by LCC.

The following SOL exceedances will be communicated between ISO and the impacted LCCs:

- IROL exceedances
- SOL exceedances of stability limits
- Post-contingency SOL exceedances that have that have been confirmed to potentially become an IROL

- Pre-contingency SOL exceedances of Facility Ratings
- Pre-contingency SOL exceedances of normal minimum System Voltage Limits

The following SOL exceedances must be communicated between ISO and the impacted LCCs if they persist for more than 30 minutes:

- Post-contingency SOL exceedances of Facility Ratings or emergency System Voltage Limits
- Post-contingency SOL exceedances of normal maximum System Voltage Limits

These communications will use the processes described in MLCC 13 – ISO and LCC Communication Practices.

When determining the start time of an IROL or SOL exceedance, ISO and any impacted LCC will use the contingency analysis that first identified the IROL/SOL exceedance. In responding to an SOL, ISO and any impacted LCC will implement all applicable pre-contingency NORMAL and EMERGENCY actions, (as defined in OP-19). Pre-contingency load-shedding may be avoided if the TO or TOP (i.e., LCC) authorizes an enhanced facility thermal or voltage limit and the LCC has developed an implementable post-contingency action plan to operate the facility within enhanced limits. When the local area involves two or more TOs, the appropriate LCC will coordinate the actions required by the TOs in response to the local area contingency. When the impacted TO(s) / LCC(s) **cannot** agree on a post-contingency action plan, all applicable pre-contingency NORMAL and EMERGENCY actions will be used to resolve the SOL. This provision shall **not** be used for IROLs.

All agreements to operate to the enhanced facility limit and the use of post-contingent action plans shall be communicated to ISO electronically, prior to implementation. Use of a recorded line is acceptable for these purposes. Written documentation of the agreements and post-contingent action plans shall be provided electronically (e.g., facsimile, email, etc.) to ISO in a timely manner, **not** to exceed 24 hours from the time the enhanced rating or limit/post-contingent action plan was first provided.

Any operation beyond an SOL for the applicable time period would **not** only constitute an exceedance, but may rise to the level of a violation. An example of this would be operation in Real-Time beyond an SOL (i.e., operation above the DAL rating). The violation determination and, if confirmed, root cause investigation, would be made following a technical review of the facts. For potential low voltage and IROL violations, such determinations are made by the ISO Operations Support Services department engineering staff in cooperation with the appropriate LCC staff. The LCC staff, with the appropriate TOs, would lead the determinations for potential high voltage violations.

5.1 Thermal SOLs

ISO performs studies in order to establish seasonal and operational planning transmission interface limits to prevent thermal overloads or cascading thermal overloads. ISO establishes these limits by evaluating system response to all the contingencies defined in OP-19, Appendix J - Contingency List and Criteria/Limits. Most of the contingencies are observed at all times and are used to determine SOLs; a subset of multi-element contingencies is only observed where the contingency could cause an IROL or cause unit instability. These studies therefore include:

a) the anticipated system conditions,

b) a range of Resource availability and transmission outage scenarios,

c) various peak load assumptions and

d) simulation of defined protection schemes (RAS/ACS) actions where appropriate.

The limits are developed such that **no** facility limits are exceeded under a base-case set of assumptions. Then, ISO evaluates system performance assuming first contingency (N-1) to evaluate whether post-contingency loadings result in an SOL. Additionally, for IROLs, ISO evaluates the system in Real-Time to determine if adequate Resources and operational actions are available to reposition the system within 30 minutes to a new operating state that allows continued reliable operation in the event that a second contingency (N-1-1) occurs. This type of analysis confirms the system can both:

a) withstand a first contingency and

b) be repositioned to withstand the second contingency within the appropriate time period (30 minutes or 120 minutes), without resulting in an IROL / SOL.

Transfer limits developed for system operation use the same methodology. For transfer limits developed for N-1-1 interfaces, opening the limiting transmission element can be utilized if:

- the facility operates at 115kV or below
- the limitation is thermally-based
- the facility would be opened post first contingency
- the ISO Control Room consulted with Real-Time Studies to determine if there were adverse voltage or stability consequences from opening the facility
- the impacted LCC was consulted and approved the post-contingent opening of the facility

For reliable operation with N-1 considerations, the same evaluation process can be used to open a breaker for limiting stuck breaker contingencies if:

- the limitation is thermally based
- the ISO Control Room consulted with Real-Time Studies to determine if there were adverse voltage or stability consequences from opening the facility

- the impacted LCC was consulted and approved the pre-contingent opening of the facility

Enhanced facility limits will be considered by ISO if provided by the TO or TOP (i.e., LCC) when a facility limit has been identified as the basis for an SOL, even in Real-Time. As noted in OP-19, the TO may provide enhanced facility limits to ISO and the LCC that reflect the impact of current ambient conditions, or other appropriate limit assumption changes, that may allow for an enhanced facility limit for a transmission facility. All enhanced facility limits provided shall be communicated to ISO electronically or over a recorded phone line prior to implementation; documentation of the enhanced facility limits in writing (e.g., facsimile, email, etc.) shall be provided electronically to ISO in a timely manner **not** to exceed 24 hours. Enhanced facility limits are expected to include two aspects - the facility limit and the allowed time duration for its use. For example, an enhanced thermal limit for a facility may be a two-minute limit to allow post-contingent actions to be applied within two minutes to return the facility to its normally utilized facility limit set (Normal, LTE, STE, and DAL). The main difference between enhanced limits and limits resulting from weather-sensitive ratings is that enhanced limits can exist for time periods shorter than those defined in our set of supported ratings (Normal, LTE, STE and DAL).

5.2 Voltage and Reactive SOLs

ISO performs studies to establish transmission interface limits to prevent cascading voltage collapse by testing all contingencies defined in OP-19, Appendix J. Most of the contingencies are observed at all times and are used to determine SOLs; a subset of multi-element contingencies is only observed where the contingency could cause an IROL. Where appropriate, simulations of defined protection scheme (RAS/ACS) actions are included in the studies.

These analyses are conducted prior to Real-Time operations and use a set of stressed system conditions, such as:

a) a range of high-load levels to aggravate low voltage problems;

b) a range of low-load levels to aggravate high voltage problems;

c) a range of Resource availability to quantify the impact on the voltage problem; and

d) inclusion of Resource and transmission maintenance conditions

These analyses are conducted using standard load-flow techniques. The analyses identify limits by either detecting an exceedance of acceptable minimum/maximum voltage limits on transmission buses or detecting the failure of simulations to converge - an event which signals a voltage collapse. Once a maximum transfer limit is determined by a convergent solution containing acceptable voltage profiles, ISO will then reduce the transmission interface limit by an engineering safety margin. The magnitude of the margin is based on reviewing the P-V system response and maintaining sufficient gradients between the pre-contingency voltages and the limiting post-contingency voltages. Typically these engineering safety margins are approximately 50 MW to 100 MW. Utilizing the study assumptions of a stressed system and operating at this reduced transfer limit provides a safety margin to protect against widespread voltage instability or collapse and prevent an IROL.

SOL identification will utilize the voltage limits supplied. A voltage SOL exceedance will occur when:

- A transmission substation has a voltage beyond the applicable voltage limit
    - Exception 1: Radial transmission stations, either by design or the result of a contingency, with voltages below the low voltage limits will **not** be considered SOLs. This exception may also be applicable, following LCC review, for voltages beyond the high voltage limits, for the duration defined by the affected LCC(s),
    - Exception 2: Any high voltage exceedance that can be mitigated in less than five minutes at 107% or less of nominal voltage (where the high limit is 105% of nominal), will **not** be considered a high voltage SOL exceedance.[2]
        - This would only apply to Real-Time conditions or Real-Time Contingency Analysis. The voltage limits in M/LCC15 Attachment H – Voltage SOL Identification Procedure (M/LCC15H), shall be used in next-day planning, which includes mitigating actions (including unit commitment) when exceedance of a high voltage limit of 105% of nominal is indicated.
- The system performance assessment determines that a voltage collapse is likely to occur. Indications of voltage collapse include:
    - a non-converged power flow solution

2 The following factors justify this determination:

- The transmission system has been planned by transmission owners allowing load-tap-changing transformers and switched capacitors / reactors to move post-contingency before application of voltage limits. Prior to movement of these devices, modest over-voltage conditions can be present for those short periods of time. Therefore, since the system has been designed and control / protection settings applied to allow these actions, the immediate post-contingency over-voltage conditions are acceptable.
- Transmission capacitors banks in New England have automatic switch out voltage setpoints over 105% of nominal (most set at 107% of nominal) with time delays varying between many seconds up to 10 minutes. These time delays have been used for years, and operation of the equipment at those voltage levels, for those short time periods, is acceptable.
- Voltage unbalance exists in all three phase power systems, and the New England system is no exception. The level of unbalance is often on the order of 1 to 2%. That means when any station voltage, monitored on a single phase basis, indicates 105% of nominal, the other phase voltages could be as high as 107%. There is no preclusion from operating at 105% of nominal for extended periods of time, which means there is no preclusion for extended periods of operation of other phases as high as 107% of nominal.

- a voltage below the defined voltage-collapse threshold documented in M/LCC15H
- rapidly dropping voltage based upon modest changes in system load or transfer, based upon system conditions, at voltage levels above the voltage limits provided by the TO

The potential for an IROL is determined through use of standard load-flow techniques for the area in question. In the determination analysis, the area is examined beyond the transfer limit to determine the subarea that may be lost due to voltage collapse. The analysis methods used to determine this subarea may include Q/V analysis using reactive power injection sources or manipulation of the limiting facility's impedance to achieve a last solution before insolubility. The IROL list from OP-19 Section II.A.1.b would be used to determine the existence of a potential IROL based upon this analysis.

SOL determination for voltage operating limits requires LCC identification of the SOL or ISO identification of the potential SOL and subsequent LCC concurrence of the SOL existence. Use of this method allows the more detailed local system modeling of the LCCs to be consulted before SOL confirmation by the LCC and ISO. Either the LCC or ISO can identify a voltage collapse SOL.

If a TO or LCC provides an enhanced limit to resolve a voltage SOL to preclude pre-contingent load shedding, they must provide the loads to be shed post-contingent to resolve the SOL.

Transmission System voltage schedules have been established for the New England Transmission System to operate within SOLs and IROLs for expected system conditions. For transmission stations with generators, dynamic reactive resources, and load tap-changing transformers, these voltage schedules are documented in OP-12, Appendix B. The resulting pre-contingency transmission operating voltage range is normally between 100% and 105% of nominal for all transmission voltage classes (115, 230 and 345 kV). The voltage schedules and resulting transmission operating range support the meeting of system voltage SOLs and IROLs based upon the voltage limits and criteria listed in OP-19 and its Appendices, and this Procedure and its Attachments.

5.3 Transient and Dynamic Stability SOLs

ISO performs studies to establish transmission interface limits to prevent unit/area instability, insufficiently damped system response, or unacceptable transient low voltage conditions. The ISO uses the following criteria and guidelines when performing stability studies:

- Steady state voltage stability : The ISO applies the voltage limits listed in OP 19 Appendix K and engineering judgement when examining voltage performance in stability analysis results
- Transient voltage response: As listed in ISO NE's Transmission Planning

Technical Guide – Appendix B

- Angular stability: Resource stability required for all tested normal criteria faults. No more than 20 MW of generation shall trip and remain off-line following a fault / fault clearance / system disturbance, at transmission or lower system voltages

- System damping: As listed in ISO NE's Transmission Planning Technical Guide – Appendix C

To do these studies, ISO conducts testing under a range of system conditions, including testing the system at light load conditions due to the reduced system damping available from load and inertia from limited online Resources. The system model tested includes all of New England, and significant detail in the adjacent RC areas, at a minimum. Significant sensitivities to Resource dispatch, reactive equipment availability, bus/breaker configurations, line/breaker-out conditions, defined protection scheme (RAS/ACS) action/in-action, etc., are all considered in the testing. RAS response may be modeled and considered for potential IROLs and SOLs, while limited RAS will only be considered for SOL outcomes and not IROLs. Under-frequency load shedding will not be relied upon at all when establishing stability limits.

The transmission interface limits are determined using standard transient stability simulations of the contingencies defined in OP-19, Appendix J and are limited by unit/area instability, insufficiently-damped system response, or unacceptable transient low voltage conditions. The list of contingencies in OP-19, Appendix J will be evaluated for revision based upon available feedback, including that from ISO NE planning on appropriate contingencies to consider for stability analysis.

Once the transfer limit is determined with acceptable dynamic performance through the analysis, ISO will reduce the transmission interface limit by an engineering safety margin of approximately 50 MW to 100 MW. At this limit, damping is evaluated to determine if the dampening criterion is met. If so, **no** additional buffer is included; if **not**, transfers are continually reduced and re-evaluated until the dampening criterion is met. As this is the case with voltage or reactive limit exceedances, it is necessary to operate at this reduced transfer limit to protect against unit/area instability, insufficiently damped system response, an unacceptable transient low voltage condition, and to prevent an SOL/IROL exceedance.

The results of the analysis, and the potential consequences for **not** adhering to the stability limit, are examined against the IROL list in OP-19 Section II.A.1.b. Machine instability for one or more units may be included as a potential IROL based upon the fact that unit instability may lead to other system concerns such as:

- Uncontrolled loss of transmission elements adjacent to, or remote from, the Resource in question:
    - The uncontrolled loss of transmission elements is an example of an "inability to determine if a discrete sub-area of the system is susceptible to voltage

collapse or uncontrolled separation from the rest of the system" (an IROL example from OP-19)

- This may lead to multiple 345 kV elements (lines, transformers and substations) being lost due to unit instability of a 345 kV-connected generator.

Finally, ISO evaluates system operations in response to the extreme contingency three-phase fault with delayed clearing in order to:

a) measure system strength;

b) determine the extent of a widespread system disturbance; and

c) impose an additional reduction in the transmission interface limit depending on the system impact.

The results of these studies are shared with impacted LCCs and adjacent RCs, as appropriate, with feedback and comments sought before finalizing the analysis and limits.

5.4 Transmission Interfaces and ILC

ISO determines N-1-1 transmission interface limits for importing areas identified as having the potential to be an IROL within the New England RCA. This is performed so that adequate post "first contingency" actions to redispatch the New England Transmission System within 30 minutes of the "first contingency" (N-1) are available and the ISO is prepared for the next contingency. ISO communicates these limits to all LCCs. ISO continually refines and updates study assumptions for identifying transmission interface limits up to and including Real-Time.

In Real-Time, ISO and LCC software (such as the ISO ILC) is configured to alert the ISO and LCC System Operators when potential exists for exceeding an SOL or IROL associated with an interface due to Real-Time system conditions. The ISO ILC interfaces are listed in Attachment J of this procedure. System Operators will pre-position Resources (e.g., generation) or take other pre-contingent NORMAL actions when system flows indicate that an IROL exceedance may occur if a contingency were to take place or, in the case of N-1-1 interface limits, if there would be inadequate actions available to redispatch the system within 30 minutes in preparation for the next contingency. In addition, ISO and LCC contingency analysis (CA) applications will identify specific stuck-breaker, bus-fault and double-circuit tower contingencies to evaluate whether they would result in a potential IROL. These specific contingencies are identified in the Attachments of this Procedure; please refer to Section 6 for a description of the Attachments.

5.5 Single Source Contingencies

Joint RC studies have concluded that the loss of a supply source at high levels of imports (greater than 1,200 MW) could have a larger effect on NYISO and PJM than the worst internal contingency that these individual systems normally protect against. ISO monitors and will dispatch its large Single Source Contingencies against the PJM and NYISO limiting interfaces such that the New England system does **not** impose an IROL on another area in Real-Time.

5.6 Real-Time Transmission Protection and Relay Outages

Transmission Owners shall notify the ISO control room of Real-Time transmission protection and relay outages as described in ISO New England Operating Procedure No. 24 - Protection Outages, Settings and Coordination (OP-24) and Master Local Control Procedure No. 7 Attachment D – Minimum Advance Notice Times – Outage Requests for Specific Equipment (M/LCC 7D).

Within the New England transmission system, the 345 kV transmission network serves as the bulk transmission paths for power transfer through the system. Outages that impact this system, and its ability to transfer power, have the greatest likelihood to impact reliability in New England

All 345 kV transmission lines in the New England Transmission System should have two relay schemes that will clear a fault anywhere on the line with **no** intentional time delay [nominally around four (4) cycles]. In general, if both high-speed protection systems are out-of-service, a fault on the affected line would be cleared by backup relay protection or intentionally time-delayed protection systems which usually take longer to clear faults, possibly leading to instability, cascading outages, and system separation. It is possible that the loss of both high-speed relay protection schemes can dynamically impose SOLs or IROLs depending on the location of affected equipment and facilities. If a high-speed system is out-of-service and the remaining high-speed system fails, a fault somewhere on the line will likely **not** be cleared high-speed. If a 345 kV line is in-service and energized while both high-speed relay schemes are out-of-service, and instruction or guidance is **not** available for this condition, one of the following actions must be taken within 30 minutes:

- Return to service one of the two high-speed protection systems
- De-energize the affected 345 kV line

De-energizing the affected 345 kV line will be the normal response to these outages.

NOTE

The following high-speed pilot schemes are used in New England to protect the 345 kV lines.

Blocking schemes (e.g., Directional Comparison with Blocking Scheme - DCB) work on the principle of the signal exchanged among all terminals during normal, no-fault or a fault outside the protected zone condition. As long as the signal is received, the terminal will **not** clear a fault even though it is detected locally. The blocking signal will stop once a fault is detected within the protected zone, thus allowing the terminals to trip and clear the fault.

The following schemes are prone to over-tripping on faults beyond the protected zone once the communication fails.

Permissive schemes (e.g., Permissive Overreaching Transfer Trip - POTT; Directional Comparison Underreaching Transfer Trip - DUTT) in addition to the local relay detecting the fault require a signal (permission) from the remote terminal to trip. Without this signal, the terminals will **not** trip; therefore a communication failure results in unreliable protection of a line.

Current Differential Scheme (Current D): Relay inputs are provided from each side of a transmission line. If the current going into the line is more than the current output, then an internal fault is indicated.

6. Identified Contingencies, Study Methodologies, Ratings, Limits and Criteria

The background, intent and application of certain identified contingencies, study methodologies, ratings, limits and criteria are described in certain M/LCC 15 Attachments (Attachments A through D). M/LCC 15 Attachments also include a list of Transmission Stations with System Voltage Criteria Exceptions (Attachment E), a list of 69 kV Facilities Currently Under ISO-NE Operational Control (Attachment F), the Voltage SOL Identification Procedure (Attachment H), and the Primary and Secondary Voltage Inter-Control Center Communication Protocol (ICCP) IDs (Attachment I).

6.1 345 kV Stuck Breaker Contingencies that can have Unacceptable Inter-Area Impacts

M/LCC 15, Attachment A - 345 kV Stuck Breaker Contingencies That Can Have Unacceptable Inter-Area Impacts, describes those 345 kV breaker failure contingencies that may result in an IROL.

6.2 345 kV Double Circuit Tower Contingencies

M/LCC 15, Attachment B - 345 kV Double Circuit Tower Contingencies, lists 345 kV double circuit tower contingencies.

6.3 Contingency Impact Evaluation

M/LCC 15, Attachment C - Contingency Impact Evaluation, describes the method that may be used to determine if a contingency may result in an IROL.

6.4 Bus Fault Contingencies

M/LCC 15, Attachment D - Bus Fault Contingencies, describes those bus fault contingencies that may result in an IROL.

6.5 Transmission System Voltage Criteria Exceptions

M/LCC 15, Attachment E - Transmission System Voltage Criteria Exceptions, lists on a station-by-station basis, exceptions to the steady-state pre-and post-contingent voltage limits contained in OP-19 Appendix K. Changes to M/LCC 15 Attachment E must be provided to ISO Real-Time Studies. Any suggested changes of consequence may be reviewed by the Voltage Task Force before implementation in M/LCC 15 Attachment E.

6.6 69 kV Facilities Currently Under ISO-NE Operational Control

M/LCC 15 Attachment F - List of 69 kV Facilities Currently Under ISO-NE Operational Control, describes those networked 69 kV facilities that are under ISO-NE operational control. All other networked 69 kV transmission facilities **not** listed in M/LCC 15, Attachment F are under the operational control of the LCCs.

6.7 High Speed Pilot Protection Schemes in 345 kV Transmission Lines

M/LCC 15 Attachment G - High Speed Pilot Protection Schemes in 345kV Transmission Lines, has been retired. TOs shall use ISO New England Operating Procedure No. 24 - Protection Outages, Settings and Coordination (OP-24) for instruction and guidance with these relay schemes.

6.8 Voltage SOL Identification Procedure

M/LCC 15 Attachment H - Voltage SOL Identification Procedure, describes the process that is to be used by ISO and the LCCs to identify voltage SOLs and categorize them as SOLs or IROLs. M/LCC 15 Attachment H provides guidelines for use by operations staff to aid in their determination.

6.9 Primary and Secondary Voltage ICCP IDs

M/LCC 15 Attachment I - Primary and Secondary Voltage ICCP IDs, identifies points of measurement used for determining Real-Time voltage SOLs at select stations, unless proven unavailable or inaccurate.

6.10 SOL and IROL Interfaces

M/LCC 15 Attachment J - SOL and IROL Interfaces, identifies the SOL and IROL Interfaces by location that can be utilized by each applicable LCC to monitor those interfaces...

6.11 Voltage Task Force Scope

M/LCC 15 Attachment K – Voltage Task Force Work Scope, defines the work scope of the Voltage Task Force (VTF) when supporting system reliability and determining the impact of the load power factor on near or actual SOL or IROL voltage exceedances.

6.12 Real-Time Assessment Data

M/LCC 15 Attachment L – Real-Time Assessment Data, describes the requirements to perform Real-Time Assessments and the data inputs that can be used to perform that process.

7. Revision History

Rev. No.	Date	Reason	Contact
---	01/13/22	For previous revision history, refer to Revision 10 available through “Ask ISO”	Dean LaForest
11	01/22/21	Annual review completed by procedure owner Globally added RAS and ACS to instances of SPS reference in document; added Note in Sections 4.1, 5.1, 5.2, and 5.3 to describe treatment of SPS identification by Operation and Field personnel	Dean LaForest
12	01/13/22	Annual review completed by procedure owner Revision history truncated per SOP-RTMKTS.0210.0010 business process	Dean LaForest
13	06/28/22	Added sentence in section 4.1 concerning Real-Time Assessment Data; Removed NOTE in sections 4.1, 5.1, 5.2, and 5.3; Clarified enhanced facility limits in Section 5.1; Added Attachment L – Real-Time Assessment Data to identify the data points used by ISO System Operators when performing Real-Time Assessments	Dean LaForest
14	06/13/23	Revision of scope of ISO outage coordination duties in light of overall review being performed by OSS management; Added 6.12 Real-Time Assessment Data.	Dean LaForest
15	03/28/24	Annual review completed by procedure owner; Added information to Background; Changes required by new FAC-011-4 going into effect on 04/01/2024; Added more specifics in terms of what voltage limits are required (section 4.2), what exceedances must be communicated between the ISO and the LCCs (and which do not need communication – section 5), a listing of the criteria / guidelines used in stability analyses, and a confirmatory statement that we share study results with LCCs and adjacent RCs as needed (section 5.3).	Dean LaForest

8. Attachments

Attachment A - 345kV Stuck Breaker Contingencies that can have Unacceptable Inter-Area Impacts (Confidential)

Attachment B - 345kV Double Circuit Tower Contingencies (Confidential)

Attachment C - Contingency Impact Evaluation

Attachment D - Bus Fault Contingencies (Confidential)

Attachment E - Transmission System Voltage Criteria Exceptions (Confidential)

Attachment F - List of 69 kV Facilities Currently Under ISO-NE Operational Control

Attachment G - Retired (02/01/19)

Attachment H - Voltage SOL Identification Procedure

Attachment I - Primary and Secondary Voltage ICCP IDs

Attachment J - SOL and IROL Interfaces

Attachment K – Voltage Task Force Work Scope

Attachment L – Real-Time Assessment Data