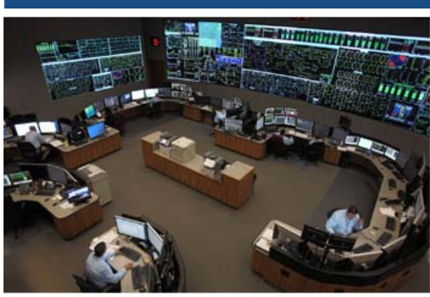
NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

IROL Framework Assessment Report

NERC Methods for Establishing IROLs Task Force (MEITF)

September 2018

RELIABILITY | ACCOUNTABILITY

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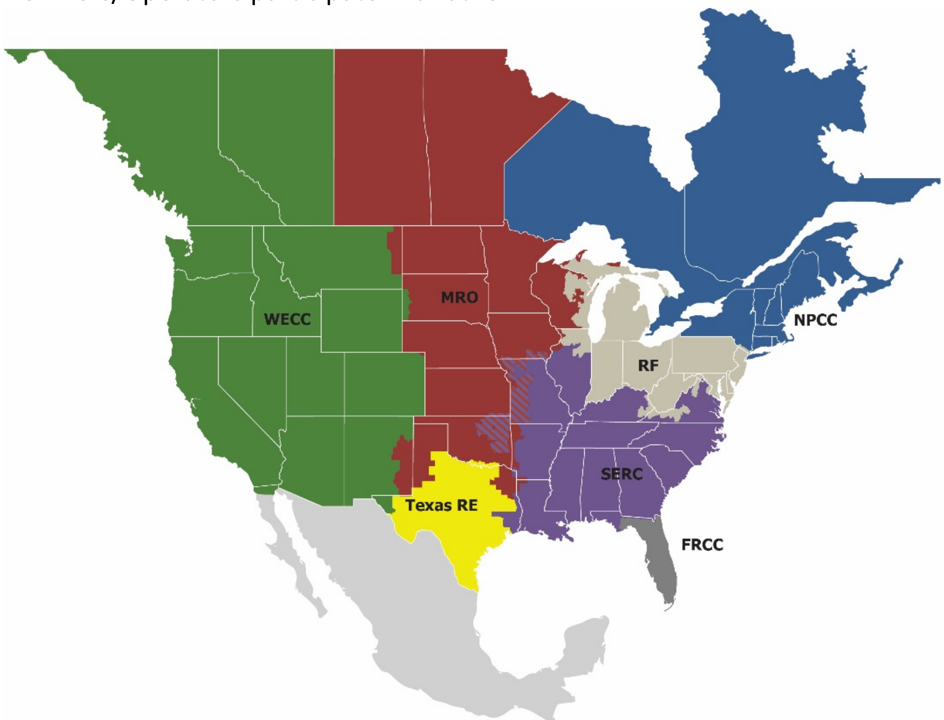
Preface

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

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



FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Executive Summary

The NERC Methods for Establishing IROLs Task Force (MEITF) was formed to provide technical guidance to the Project 2015-09 FAC Standard Drafting Team (SDT) for potential revisions to the FAC standards requirements. One of the tasks assigned to the MEITF focused on reviewing the technical aspects of how IROLs are established (the "IROL framework"), and recommend potential revisions to the FAC Standards for consideration by the FAC SDT.

The MEITF presented an IROL framework based on the technical rationales and consensus of industry stakeholders (MEITF membership and NERC Planning Committee (PC) and Operating Committee (OC)), including recommended revisions to the NERC FAC standards as well as proposed revisions (and additions) to the NERC Glossary of Terms to support the IROL framework and revised standards requirements. Following approval of the IROL framework by the NERC PC and OC membership, FERC staff expressed concerns regarding approval of the proposed changes to NERC Standards. Based on the concerns, the NERC MEITF attempted to develop an alternative IROL framework that the MEITF believes could be endorsed by FERC staff, based on their concerns about the approved framework. While the MEITF does not endorse this alternative framework, this document attempts to describe technical aspects of both frameworks and the potential challenges of implementing the framework that is believed to be supported by FERC staff. This includes qualitative and quantitative examples as well as discussion related to potential benefits and challenges of using either the original industry-supported IROL framework or the IROL framework to address FERC staff concerns. This document focuses on these concepts and includes the following:

- Presentation of the IROL frameworks
- Technical considerations and review of IROL frameworks
- RC questionnaire related to IROL frameworks
- Qualitative and quantitative examples of applying IROL frameworks

Key Findings and Recommendations

The key findings and recommendations described in Table ES.1 are describe in detail throughout this guideline, and are listed in their respective sections.

Table ES.1: Key Findings and Recommendations

#	Key Finding	Recommendation
1	Responses from RCs regarding whether there would be an increase in the number of IROLs if the industry adopted the framework believed to be supported by FERC varied significantly. This is dependent on existing RC practices (e.g., how they treat SOLs versus IROLs) and operating plans as well as system characteristics. Most of the increases were attributed to cascading and localized voltage instability. Some RCs stated that they would see an increase in pre-contingency load shedding due to the establishment of IROLs, as compared to existing practices.	The MEITF is providing information regarding impacts to existing practices for reference for a future SDT. A future SDT should take these findings into consideration when developing IROL-related standards requirements.
2	Instability, uncontrolled separation, or cascading needs to be quantified such that its impact to the BES is understood ahead of real-time operations. The inability to quantify impact is a serious reliability risk and warrants establishment of an IROL. The MEITF has devised a proposed term for the NERC Glossary of Terms deemed "System Instability" used to describe situations where any type of instability is either unable to be proved to be contained or proved to be too large of an impact to the overall reliability of the BES.	Any instability, uncontrolled separation, or cascading whose impact cannot be quantified should warrant establishing an IROL. On the other hand, more localized instability conditions proved to be contained to a local area ahead of real-time operations should not necessarily warrant establishing an IROL in all situations.

Table ES.1: Key Findings and Recommendations		
#	Key Finding	Recommendation
3	The establishment of IROLs to prevent any instability, uncontrolled separation, or cascading can present challenges especially for local load service areas where minor instability or cascading events may result in a small amount of load loss. The load service reliability is significantly degraded when shedding load pre-contingency compared to taking the risk of a very low probability contingency occurring that would result in the contained instability, uncontrolled separation, or cascading affective a relatively small amount of load.	Widespread impacts (impacting neighboring RCs, large areas of single RC footprint, etc.) warrant establishing an IROL. However, local instability, uncontrolled separation, or cascading that is proved to be contained to a relatively small amount should not necessarily warrant the establishment of an IROL. Local load issues, and the potential for load loss, should be left up to the local RC to make that determination based on their own risk assessment. Many RCs currently have fairly extensive risk assessment methods for determining whether to establish an IROL on a case-by-case basis.
4	Transient (angular) instability should be quantified and well understood; if the instability cannot be quantified, it warrants establishment of an IROL. Transient instability may or may not have an adverse impact to the BES, based on the system topology and criticality of generation to overall BES reliability. Generator loss of synchronism or other transient instability may not necessarily result in load loss, or the load loss may be minimal and can be restored quickly. Mitigating a unit instability with an IROL versus an SOL has little reliability benefit unless the overall BES is at risk.	Instability that is proved to have no adverse impact to the BES (i.e., does not result in tripping additional (or minimal) transmission elements or load) should not be mitigated with an IROL. Rather, an SOL with appropriate operating plans should be used to return to operating conditions that mitigate the instability.
5	The definition of cascading that currently uses the term widespread creates ambiguity on how it gets practically applied. A definition that eliminates this term is proposed by the MEITF. Some determination of acceptable versus unacceptable levels of cascading is therefore required to gain consistency across RCs for use in developing SOLs versus IROLs. Allowing some amount of load tripping during cascading is reasonable due to minor load pockets and tapped loads tripping during bounded, contained, pre-studied conditions.	Any future revisions by a FAC Standards SDT should consider updating the cascading definition in the NERC Glossary of Terms. Subsequently, any revisions to the FAC Standards requirements (or specified in the RC SOL Methodology) should then specify what is considered acceptable versus unacceptable cascading for purposes of IROL establishment. Some degree of cascading that is bounded, studied ahead of real-time operation, and proved to be contained should not warrant establishment of an IROL. Minor load loss caused by cascading should be acceptably managed through SOLs rather than through the use of an IROL.
6	Pre-contingency load shedding is not the most appropriate action to mitigate potential violations in reliability criteria, and may result in a degradation in reliability of load service. In some situations, post-contingency operator actions can suffice to eliminate the potential risk (e.g., cascading in some cases) without requiring the use of pre-contingency load shedding. Further, studies may prove a contained amount of load loss with no impact to the remaining BES, and should also suffice without taking pre-contingency action.	When the load loss amount is proved to be contained (and possibly below some acceptable level), post-contingency load loss or load tripping may be sufficient and may also improve overall reliability of load service to end-use customers. These situations should not necessarily require the use of pre-contingency load shedding and a necessary actions, and therefore may not warrant the establishment of an IROL.
7	Applying the definition of uncontrolled separation is often challenging for study engineers since reliability studies use known contingencies and operating conditions. Uncontrolled separation applied to small load pockets or generators that have no adverse impact to the BES can be problematic.	Uncontrolled separation should focus on large portions of the BES separating from the rest of the BES. These conditions are well understood in the regions that have these potential issues under certain operating conditions, and IROLs are established accordingly. However, it is not appropriate to apply this concept to smaller load pockets or individual generator(s).

Table ES.1: Key Findings and Recommendations		
#	**Key Finding**	**Recommendation**
8	The system is planned to meet the performance requirements specified in Table 1 of TPL-001-4 while serving all firm load and including all known firm transmission commitments. If the system is operating the same condition that it was planned for, category P0, there will be no Instability, Cascading, uncontrolled separation, exceedance of facility ratings, or violation of voltage limits for the next contingency. However, since operating conditions often vary from planned conditions, the RC may need to establish IROLs that were not identified in the planning horizon. The RC may shed load pre-contingency to remain within those IROLs; whereas, the planner is prohibited from shedding pre-contingency load. This is logical since the RC may be in an operating condition more severe than the events the system was planned for. However, enhanced coordination on sensitivity studies and operating procedures used in planning and operating analyses could reduce differences between the system conditions studied by the planners and the RC.	A future SDT should consider how the TPL and FAC standards work in concert related to establishing IROLs versus developing corrective action plans to address reliability criteria in the planning horizon. Consideration should be given to the methods planners employ when utilizing operating procedures as part of the corrective action plans.
9	RCs used different methods for applying selected contingency events to the studies for establishing SOLs and IROLs.	Proposed revisions to FAC-011 should address this ambiguity in how selected contingency events in FAC-011, Requirement R5 are applied to studies to establish or set SOLs and IROLs. In particular, the RC should have flexibility in determining how selected contingencies are applied for SOLs and IROLs based on a risk assessment.
10	Unforeseen conditions (e.g., forced or urgent outages) may arise where the unplanned or unforeseen operating conditions do not match the planned, expected conditions. In those cases, priority is given to returning relatively quickly to a state where the system performs acceptably for the next contingency event. On the other hand, IROLs and other SOLs are studied and set accordingly to expected operating conditions (e.g., elements out, load levels, transfers). The limit values may be updated as real-time approaches, yet are typically set in advance.	It should be made very clear in any FAC standards revisions that IROLs are established for expected operating conditions. IROLs should be established prior to real-time operation and may be updated as real-time conditions near or during real-time operations. At the very least, the time allowed to proceed with corrective actions should be different for planned conditions (“N” system) versus following a contingency (“N-1” system) to allow considerations for risk mitigation and probability of occurrence of a second contingency. RCs should study multiple contingencies deep, particularly for stability-related SOLs and IROLs where the post-contingency risk is greater.
11	Any consideration for whether an SOL should be an IROL includes some degree of risk assessment by the RC, otherwise all SOLs related to instability, uncontrolled separation, and cascading would be considered an IROL irrespective of the severity of impact or the relative risks involved on a case-by-case basis. Risk assessment provides the RC with flexibility while ensuring some degree of consistency across all RCs.	Some degree of risk assessment should be allowed by the RC to provide flexibility in the way that IROLs are established. Requiring that all instability, uncontrolled separation, and cascading be mitigated with an IROL should be avoided because it will result in substantially more pre-contingency load shedding for instability, uncontrolled separation, and cascading conditions that are known to be bounded, contained, and have minimal risk to the overall BES.
12	The analytical techniques used for studying the impacts of instability, uncontrolled separation, and cascading are not well documented across SOL Methodologies. The Reliability	The techniques presented in the guideline should be considered by RCs when developing their SOL Methodologies.

Table ES.1: Key Findings and Recommendations		
#	Key Finding	Recommendation
	Guideline: Methods for Establishing IROLs developed by the MEITF seeks to fill that technical gap and provide relevant guidance for the industry. The guideline provides technical information independent of any IROL framework or potential revisions to NERC Reliability Standards.	
13	IROLs are used in a number of other NERC Reliability Standards, which can create additional burdens and compliance obligations when establishing IROLs. These links may not be necessary and have possibly led to IROLs not being used temporarily, as they should be, due to these linkages. It is possible that these linkages have discouraged the establishment of IROLs altogether.	MEITF supports the efforts by the SDT to propose revisions to NERC Reliability Standards that eliminate the link between IROLs and the other NERC Reliability Standards that are not related to real-time operations (i.e., specific FAC, IRO, and TOP NERC Reliability Standards). Those proposed revisions allow for IROLs to be established and used solely as for operating purposes. This separation should result in IROLs being used more appropriately in temporary situations such as maintenance outages. The SDT has proposed revisions to the standards to ensure that there are no reliability gaps, and that the intent of those other standards can be fulfilled.

Background

The NERC Methods for Establishing IROLs Task Force (MEITF) was formed to provide technical guidance to the Project 2015-09 FAC Standard Drafting Team (SDT) for potential revisions to the FAC standards requirements. The MEITF scope of work included developing technical reference material related to the techniques and analysis for studying instability, uncontrolled separation, and cascading. The other major aspect of the MEITF work focused on reviewing the technical aspects of the IROL frameworks, and developing potential revisions to the FAC Standards for future consideration by the FAC SDT.

The MEITF has developed a draft *Reliability Guideline: Methods for Establishing IROLs*, which is intended to provide technical guidance for analyzing instability, uncontrolled separation, and cascading. That document is a standalone reference that, once approved, should be considered for inclusion in all RC SOL Methodologies. The concepts discussed in that guideline are not discussed here. This report focuses on the IROL framework, and technical aspects related to the revision of IROL-related standards requirements.

The MEITF presented a proposed IROL framework based on the technical rationales and consensus of industry stakeholders, including recommended revisions to the NERC FAC standards, to the NERC Planning Committee (PC) and Operating Committee (OC) who approved the IROL framework as presented. The NERC PC and OC also approved a set of revised terms for consideration by the FAC SDT for inclusion in the NERC Glossary of Terms that supported the IROL framework and revised standards requirements. Following approval of the IROL framework by the NERC PC and OC, FERC staff expressed concerns regarding approval of the proposed changes to NERC Standards. Based on the concerns, the NERC MEITF attempted to develop an alternative IROL framework that the MEITF believes could be endorsed by FERC staff based on their concerns about the approved framework. While the MEITF does not endorse this alternative framework, this document attempts to describe technical aspects of both frameworks and the potential challenges of implementing the framework that is believed to be supported by FERC staff. This includes qualitative and quantitative examples as well as discussion related to potential benefits and challenges of using either the original industry-supported IROL framework or the IROL framework to address FERC staff concerns. This document focuses on these concepts and includes the following:

- Presentation of the IROL frameworks
- Technical considerations and review of IROL frameworks
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- Qualitative and quantitative examples of applying IROL frameworks

Proposed Frameworks

As described above, two frameworks have been developed:

- **Framework A:** The IROL framework developed and supported by MEITF membership and approved by the NERC PC and OC.
- **Framework B: The IROL framework developed by MEITF to address concerns relayed from FERC staff regarding Framework A.**

Framework B is not supported by MEITF membership; rather, it is a significant effort by the MEITF to develop a framework that would likely be adopted by FERC based on FERC Staff comments. Framework B is provided for technical reference, and technical discussion throughout this document elaborates on the various considerations that should be made when moving forward with any framework.

Note that both frameworks use the definitions that are provided in Table B.1. The definitions for Instability, System Instability, Uncontrolled Separation, and Cascading are the same as proposed by the MEITF in their originally proposed definitions that were endorsed by the NERC PC and OC. The definition for IROL was modified after receiving FERC feedback, and IROL Tv was unchanged.

Framework A – Original Framework

The framework presented below was developed by the NERC MEITF, and approved by the NERC Planning and Operating Committees. It was intended to provide recommendations for modifications to the FAC standards for consideration by the Project 2015-09 FAC Standards SDT related to the establishment of SOLs and IROLs governed by the SOL Methodology. The FAC Standards describe the items that are required to be addressed in each RC's SOL Methodology, and related requirements in FAC-014 require entities to establish SOLs and IROLs consistent with the SOL Methodology. The MEITF maintains that this proposed framework portrays practices consistent with current industry efforts, and is also a significant improvement to the current status of the IROL establishment process documented in the enforceable standards. Although the framework gives a certain level of discretion to the RC regarding its assessment of IROLs, it defines clear elements and boundaries (which are nonexistent today) to incorporate in the SOL Methodology.

Each Reliability Coordinator shall include in its SOL Methodology a description of how the subsets of SOLs that qualify as IROLs are established. This methodology should, at a minimum:

1. Describe the analytical techniques used to study and determine Instability, System Instability, Uncontrolled Separation, and Cascading
2. Require that IROLs are established to prevent System Instability
3. Require that loss of load greater than 2000 MW caused by Instability, Uncontrolled Separation, or Cascading is unacceptable and warrants the establishment of an IROL
4. Establish a risk assessment process for determining which SOLs should be considered IROLs to prevent an unacceptable loss of load between 300 MW and 2000 MW due to Instability, Uncontrolled Separation, or Cascading. This risk assessment process shall, at a minimum, include considerations for:
    a. Amount of pre-contingency load shedding necessary
    b. Resulting impacts to neighboring Reliability Coordinator Areas
    c. Nature of the load (e.g., economics, criticality, geographic region, etc.) at risk
    d. Restoration plans and estimated time to restore the affected load at risk
    e. Risk of contingencies more severe than single contingency events

Framework B – Revised Framework to Address Regulatory Concerns

NERC MEITF decided to develop a framework, presented below, to address potential regulatory concerns. This framework is not supported by NERC MEITF membership. Rather, it is intended to show the contrast between frameworks and provide a venue to describe the technical aspects of each framework in a side-by-side manner.

The SOL Methodology shall require that IROLs be established for expected[1] operating conditions (including planned outage conditions) to prevent the Contingencies selected in (FAC-011-_) Requirement R_[2] from resulting in:

1. Any System Instability
2. Any voltage Instability
3. Any transient Instability, excluding unit Instability:
    a. That does not result in the apparent impedance swings causing the tripping of any Transmission system Elements other than the generating unit(s) and its directly connected Facilities.
    b. Resulting in no exceedance of emergency Facility Ratings and emergency System Voltage Limits upon loss of the unit(s) due to transient Instability
4. Any Cascading resulting in load loss
5. Any Uncontrolled Separation

Table B.1: Proposed Revised Glossary Definitions Associated with IROLs

Continent-Wide Term	Definition
Instability	The inability of Elements of the Bulk-Power System, for a given initial operating condition, to regain a state of operating equilibrium after being subjected to a Disturbance.
System Instability[3]	The inability of the Bulk-Power System*, for a given initial operating condition, to regain a state of operating equilibrium after being subjected to a Disturbance. *Refers to the remaining portion of the interconnected Bulk-Power System, with the exception of the Elements disconnected as a result of the Disturbance.
Uncontrolled Separation	The unintended islanding of a portion of the Bulk-Power System that includes generation or load.
Cascading	The uncontrolled successive loss of Bulk-Power System Elements triggered by a Disturbance.
Interconnection Reliability Operating Limit (IROL)	A System Operating Limit that, if exceeded, could lead to System Instability, Uncontrolled Separation, or Cascading that adversely impact the reliability of the Bulk Electric System.
IROL Tv	The maximum time that an Interconnection Reliability Operating Limit can be exceeded. Each Interconnection Reliability Operating Limit's Tv shall be less than or equal to 30 minutes.

[1] "expected" refers to studies performed to assess expected or anticipated operating conditions one or more days earlier than real-time operations. The intent with this language is to convey that IROLs are not required to be established for unanticipated or unexpected operations such as forced outages or other unforeseen events over which the operator has no control.

[2] Both underscores in this sentence are intended as placeholders for pointing to the appropriate requirement once integrated into the new FAC-011 standard.

[3] As per the draft Reliability Guideline: "Instability that cannot be sufficiently proven via study to be contained to a pre-determined area should be identified as System Instability. In these cases, simulation results are inconclusive as to the extent or impact such an Instability may have on the BPS."

Chapter 1: Assessment Questionnaire

The MEITF membership developed an informal survey to understand the impacts that the proposed Framework A and Framework B could potential have in terms of number of new IROLs, drivers of new IROLs, and impacts to pre-contingency load shedding. Table 1.1 shows the responses regarding if Framework B was implemented. In the survey, the following questions were posed to gain a high-level understanding of the impacts that implementing Framework B would have on existing practices:

- If the framework were adopted, how many additional IROLs would you have (beyond the IROLs you currently have)?
- For each additional IROL, explain the main driver of the IROL (e.g., voltage instability, cascading, etc.).
- Would there be an increase in pre-contingency load shedding that would be required to remain within these IROLs (e.g., a small amount, an order of magnitude more, etc.)? Please ballpark if possible.
- Do you believe there will be a substantial increase in temporary IROLs to manage planned outage conditions? Please explain your Yes or No question.

Responses varied significantly. This was particularly due to the fact that analyzing historical conditions of whether an IROL would have been established (or for future conditions) is exceedingly challenging. Many RCs used engineering judgment to make estimations on future conditions. Some RCs stated they would see a substantial increase in new IROLs while other RCs stated they would have little to no impact on existing operating practices. For those RCs that would have new IROLs, those were predominantly driven by voltage instability cases in local load pockets and cascading events that resulted in load loss (yet are bounded). Whether pre-contingency load shedding would increase is really based on each RC's network topology and operating practices. Responses varied from significantly more to no increase in pre-contingency load shedding.

Table 1.1: Questionnaire Responses

Reliability Coordinator	Increase in IROLS	Drivers	Increase in Pre-Contingency Load Shedding?
ERCOT	Likely significantly higher.	Voltage instability	Order of magnitude more
FPL*	0	N/A	N/A
HQ	Few dozen	Cascading, voltage instability	Higher risk, and more drastic system redispatch actions
ISO-NE	5	Voltage instability	No
MISO	Studies needed, but increase	Voltage instability	Yes
NB	0	N/A	N/A
NYISO	0	N/A	N/A
IESO	40+	Cascading, voltage instability	Yes

Table 1.1: Questionnaire Responses			
Reliability Coordinator	**Increase in IROLS**	**Drivers**	**Increase in Pre-Contingency Load Shedding?**
Peak	30-35	Cascading	Yes, possibly frequently in some small load pockets
PJM	Non-response	N/A	Non-response
SaskPower	0, studies needed.	N/A	N/A
Southern	10-15	Instability with lines out-of-service	N/A
SPP	No	N/A	N/A
TVA	More than 5	Voltage instability	No
VACS	Studies needed	Voltage instability, transient instability	Possibly

* FPL (MEITF member) informally provided a response for the FRCC.

Key Finding:
Responses from RCs regarding whether there would be an increase in the number of IROLs varied significantly. This is dependent on existing RC practices (e.g., how they treat SOLs versus IROLs) and operating plans as well as system characteristics. Most of the increases were attributed to cascading and localized voltage instability. Some RCs stated that they would see an increase in pre-contingency load shedding due to the establishment of IROLs, as compared to existing practices.

Recommendation:
The MEITF is providing information regarding impacts to existing practices for reference for a future SDT. A future SDT should take these findings into consideration when developing IROL-related standards requirements.

Chapter 2: Considerations for an IROL Framework

This section describes technical considerations that should be strongly considered when developing a framework for IROL-related standards requirements. These should be considered for any future FAC standards revisions. Two key principles that the MEITF believes need to be stated up front include:

- **Use of SOLs:** It is critical to understand that both frameworks use SOLs to address *all* cascading, instability, and uncontrolled separation. The difference between the frameworks is that Framework A provides flexibility in using SOLs to address some forms of instability, uncontrolled separation, and cascading (rather than using an IROL), and reserves IROLs for instability, uncontrolled separation, and cascading that impacts a more substantial portion of the BES. On the other hand, Framework B uses IROLs to address almost all forms of instability, uncontrolled separation, and cascading regardless of impact.
- **MEITF Position:** The MEITF strongly disagrees with the principles and implications behind the framework that is believed to be endorsed by FERC staff (Framework B, presented below). Namely, the concept that almost all SOLs with potential post-contingency acceptable bounded loss of elements or load should be classified as IROLs and mitigated as such poses significant issues with reliable operation of the BES as well as providing reliable load service. It is widely recognized that IROLs are a means to put an additional level of scrutiny on parts of the system where reliability of the interconnection could be compromised if the critical contingency were to occur. The MEITF contends that using SOLs to avoid instability, uncontrolled separation, and cascading does not imply that those phenomena are acceptable. The existing SOL framework and body of NERC Reliability Standards, along with the proposed improvement by the FAC SDT, requires engineering analysis and operating plans to ensure reliable operation of the BES. However, the MEITF discussions and examples revealed that establishing IROLs to manage almost all limits (as proposed by FERC staff) would not be logical, would pose significant compliance burden, and be detrimental to BES reliability.

The following topics are described in detail in subsequent subsections of this report:

- **Quantifying Impacts:** Any instability, uncontrolled separation, or cascading should be quantified such that its impact on the BES is well understood heading into real-time operations. Any instability, uncontrolled separation, or cascading whose impact cannot be quantified should warrant establishing an IROL. Other local areas that can be quantified and contained to a pre-defined area of impact may not warrant establishing an IROL in all situations.
- **Load Loss Threshold:** Use of a load loss threshold in the IROL framework was proposed and subsequently unsupported by FERC Staff. Both the use of a load loss threshold and the unlikelihood that FERC staff will support this should be considered when developing Reliability Standards requirements.
- **Considering Local Load Service:** IROLs should protect the overall interconnection from potential widespread reliability issues rather than addressing local load service issues. The ramifications of establishing an IROL for these issues may result in reduced reliability for end-use customers. As more IROLs are established for local issues, where mitigation options are limited, it is expected that there will be more instances of pre-contingency load shedding that will be required to remain below the IROL. This translates to reduced reliability for those end-use customers.
- **Forms of Transient Instability:** Some forms of transient instability do not warrant the establishment of an IROL and can be managed with an SOL (e.g., local unit(s) instability that is proven to have no negative reliability impact to the rest of the interconnection).
- **Bounded Cascading and Load Loss:** Updates to the cascading definition should improve its application for use when establishing IROLs, and some forms of cascading that are proved to be contained with some bounded load loss should not warrant establishment of an IROL.

- **Pre-Contingency Load Shedding:** Some situations may warrant allowing post-contingency load shedding when time is allowed to take operator actions. Not all SOLs should necessitate pre-contingency load shedding action by the system operator. However, establishing and communicating ratings is paramount.
- **Analyzing Uncontrolled Separation:** Uncontrolled separation should focus on large portions of the BES separating from the rest of the BES. These conditions are well understood in the regions that have these potential issues under certain operating conditions, and IROLs are established accordingly. However, it is not appropriate to apply this concept to smaller load pockets or individual generator(s).
- **Alignment Issues between Planning and Operations:** Future efforts should consider ways in which the NERC TPL and FAC standards can work in concert related to establishing operating limits versus developing corrective action plans. Performance criteria between the two horizons should be relatively uniform, yet mitigating actions may be different in each horizon. Mainly, the way planners perform studies may not be aligned with the reality of the operations horizon, and IROLs are a very stringent concept for operators versus what the system was planned for.
- **Contingency Selection:** Proposed revisions to FAC-011 should address the ambiguity in how selected contingency events in the current draft version 4 of FAC-011, Requirement R5 are applied to studies to establish or set SOLs and IROLs. In particular, the RC should have flexibility in determining how selected contingencies are applied for SOLs and IROLs based on a risk assessment.
- **Establishing IROLs for Expected Operating Conditions:** IROLs are established to prevent adverse impacts for the next single contingency or credible multiple contingency for expected operating conditions. IROLs should be established prior to real-time operation and the limit values may be updated as real-time conditions near or during real-time operations. IROLs are not required to be established in same-day or real-time for unexpected operations such as forced outages or other unforeseen events over which the RC has no control. While such conditions need to be mitigated, these mitigations occur outside the auspices of the IROL.
- **Understanding Risk:** Risk assessment should be allowed by the RC to provide flexibility in the way that IROLs are established. Requiring that *all* instability, uncontrolled separation, and cascading be mitigated with an IROL could result in substantially more pre-contingency load shedding for instability, uncontrolled separation, and cascading that are known to have minimal risk to the overall BES. A clear distinction must be made between load service and overall system integrity/reliability for low probability, high impact events.
- **Recommended Analytical Methods:** The *Reliability Guideline: Methods for Establishing IROLs* provides detailed reference material from which RCs should pull pertinent information to develop effective SOL Methodologies. All RC SOL Methodologies should be reviewed such that they provide explicit documentation on how instability, uncontrolled separation, and cascading are analyzed and how each are characterized as IROLs. This alone will result in a significant improvement in gaining consistency across RC SOL Methodologies and in executing studies consistently.
- **Separation of IROLs from Use in Other Reliability Standards:** The MEITF is aware that the FAC SDT is revising other Reliability Standards to eliminate the linkage between IROLs and other activities. The MEITF supports this approach and believes the affected standards can be addressed in other ways. This may lead to a willingness to use operating limits more appropriately since there are less external ramifications that are unrelated to real-time operation.

Quantifying Impact

The MEITF agreed unanimously that any instability, uncontrolled separation, or cascading should be quantified such that its impact on the BES is well understood heading into real-time operations. Any instability, uncontrolled separation, or cascading whose impact cannot be quantified should warrant establishing an IROL. All RCs agreed that, while conservative and stringent, this concept is built into their existing practices today. The MEITF has even devised a proposed term for the NERC Glossary of Terms deemed “System Instability” used to describe situations where any type of instability is either unable to be proved to be contained or proved to be too large of an impact to the overall reliability of the BES.

On the other hand, the MEITF also agreed that more localized instability conditions that are proved to be contained to a local area ahead of real-time operations may not warrant establishing an IROL in all situations. Under certain operating conditions, some load may be at risk of loss due to instability, uncontrolled separation, and cascading. However, the loss of load due to the instability, uncontrolled separation, or cascading should be relatively small in electrical size (MW) as well as geographic size (only a relatively small group of buses). Examples of situations that may not necessarily warrant the establishment of an IROL, according to the MEITF, could include:

- Voltage instability of a small local load pocket where the boundary of the instability is quantified and proved to be local to a specific number of buses (see Figure 2.1).
- Cascading that is proved to be contained (see Figure 2.2). Cascading analysis may show that multiple elements could subsequently trip; however, in many cases, the cascading is bounded to only a small number of elements and does not spread to a wide area.

Both Framework A and B use the term “System Instability” to clearly differentiate those types of instability that are not quantifiable or that have a significant impact on interconnection reliability. Framework A provides flexibility to the RC to apply a risk framework for instability, uncontrolled separation, and cascading that is quantified to be contained to a specific area (and load loss amount). On the other hand, Framework B does not allow for load loss caused by these phenomena and therefore quantifying the impact is not as relevant. Framework B does not provide flexibility to the RC, and states that instability (excluding unit instability), uncontrolled separation, and cascading should be mitigated with an IROL in almost all instances. Regardless, the MEITF still believes that explicitly calling out System Instability is an effective means of gaining consistency across industry.

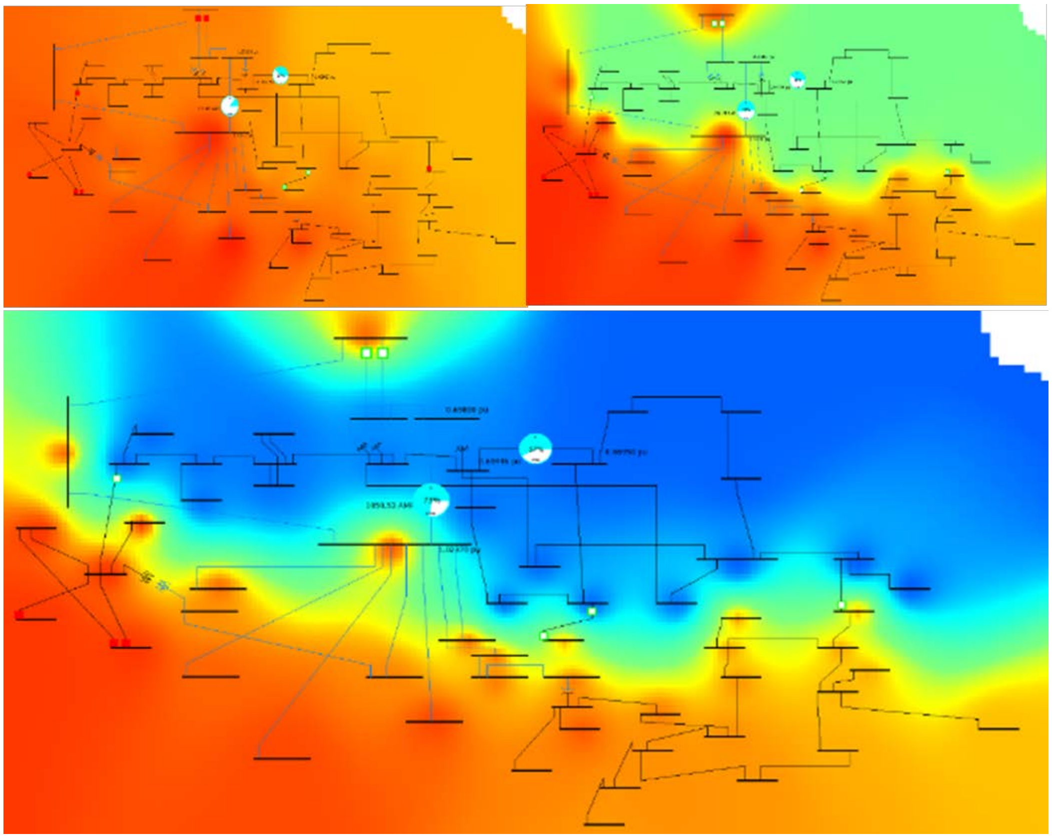

Figure 2.1: Local Voltage Instability Example

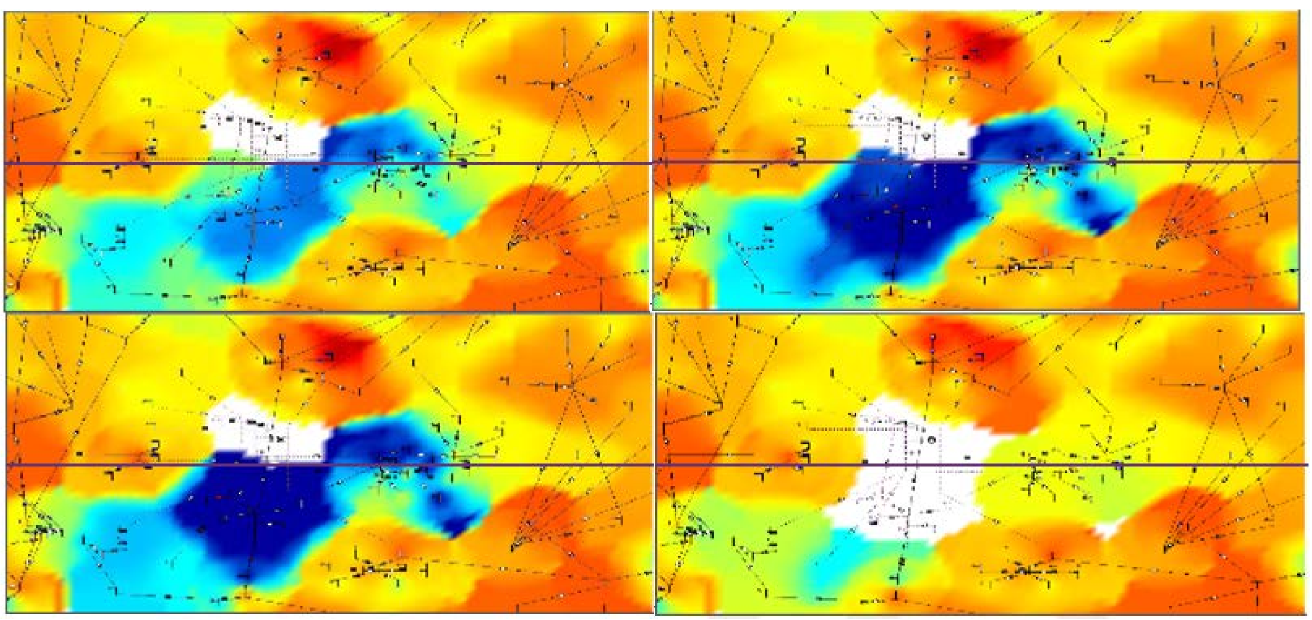

Figure 2.2: Contained Cascading Example

Key Finding:
Instability, uncontrolled separation, or cascading needs to be quantified such that its impact to the BES is understood ahead of real-time operations. The inability to quantify impact is a serious reliability risk and warrants establishment of an IROL. The MEITF has devised a proposed term for the NERC Glossary of Terms deemed "System Instability" used to describe situations where any type of instability is either unable to be proved to be contained or proved to be too large of an impact to the overall reliability of the BES.

Recommendation:
Any instability, uncontrolled separation, or cascading whose impact cannot be quantified should warrant establishing an IROL. On the other hand, more localized instability conditions proved to be contained to a local area ahead of real-time operations should not necessarily warrant establishing an IROL in all situations.

Considering Local Load Service

The MEITF discussed at length the potential situations where IROLs should be used to protect against instability, uncontrolled separation, and cascading. The MEITF agreed that widespread impacts (impacting neighboring RCs, large areas of single RC footprint, etc.) warrant establishing an IROL. However, the MEITF disagreed with FERC Staff regarding the situations in which IROLs should protect against *local* instability, uncontrolled separation, or cascading condition (particularly the instability events). In the real-time operations horizon, IROLs are intended to protect against fairly large-scale or widespread impacts to the BES and not necessarily local load issues. Instability of local load pockets or cascading that results in small amounts of tapped load, for example, should not justify establishment of an IROL.

Many of the situations where the potential establishment of an IROL becomes problematic involve using an IROL to prevent *any* instability or *any* cascading event, particularly in local load pockets. The NERC TPL Reliability Standard allows for shedding non-consequential load loss between an N-1 contingency and another N-1 contingency (N-1-1 situation). The planner can shed the load either after the first contingency or after the second, depending on practices. The operating conditions where these issues arise in real-time is almost never all-lines-in-service conditions, and typically involves one or more line outages in the initial operating state. Rather than establish an IROL and invoke shedding load pre-contingency, the RCs have opted to take the risk of potential contained instability or cascading in these situations. The amount of load loss may be higher, but the likelihood of the critical contingency occurring is very low. Therefore, from a risk perspective, it is logical to assume that risk to ensure continuity of serving load to the greatest extent possible.

The illustrative examples in Chapter 3 highlight the issue of serving the load with the highest degree of service, and how establishing an IROL to prevent post-contingency load loss by regularly shedding load pre-contingency is rarely an economical or reliable practice.

Key Finding:
The establishment of IROLs to prevent *any* instability, uncontrolled separation, or cascading can present challenges especially for local load service areas where minor instability or cascading events may result in a small amount of load loss. The load service reliability is significantly degraded when shedding load pre-contingency compared to taking the risk of a very low probability contingency occurring that would result in the contained instability, uncontrolled separation, or cascading affective a relatively small amount of load.

Recommendation:
Widespread impacts (impacting neighboring RCs, large areas of single RC footprint, etc.) warrant establishing an IROL. However, *local* instability, uncontrolled separation, or cascading that is proved to be contained to a relatively small amount should not necessarily warrant the establishment of an IROL. Local load issues, and the potential for load loss, should be left up to the local RC to make that determination based on their own risk assessment. Many RCs currently have fairly extensive risk assessment methods for determining whether to establish an IROL on a case-by-case basis.

Forms of Transient Instability

The NERC TPL-001-4 Reliability Standard, Requirement R4.1 (shown below) states that generating units are not allowed to pull out of synchronism for P1 single contingencies with normal system initial conditions. However, in real-time operations, the system is very rarely operated with all elements in service. Typically multiple elements are out-of-service and the system is not operating near the studied conditions from the long-term planning horizon. Therefore, it is generally reasonable to associate any real-time operating condition as already beyond an all-lines-in-service state.

TPL-001-4 states that for P2 through P7 contingencies, a generator is allowed to pull out of synchronism in simulation so long as the apparent impedance swings do not result in tripping of any transmission elements other than the generating unit and its directly connected facilities. It therefore would be reasonable to extend this concept to real-time operations and allow for units to lose synchronism so long as their instability does not negatively impact the rest of the BES.

4.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.

- **4.1.1.** For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.
- **4.1.2.** For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.
- **4.1.3.** For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

Unless transient instability (or other controls-related instability) of generating units causes adverse impacts to the BES, these types of instability should not warrant establishment of IROLs. One or multiple units may lose synchronism during rare outage conditions if the critical contingency were to occur. Yet that instability can be proved via simulation ahead of time to have no impact on the remaining BES. Figure 2.3 shows an example of rotor angles where one generator is losing synchronism compared to the rest of the system. This may occur at a single unit, a single plant, or multiple units at one or more plants depending on the topology of generation and transmission for the system under consideration. All of these situations may result in the same condition of instability with little to no impact to the rest of the BES. For this reason, they should be considered as forms of instability that do not warrant establishment of an IROL. In these cases, an SOL should be established to protect against the instability. However, establishing an IROL will not result in any further improvement to BES reliability.

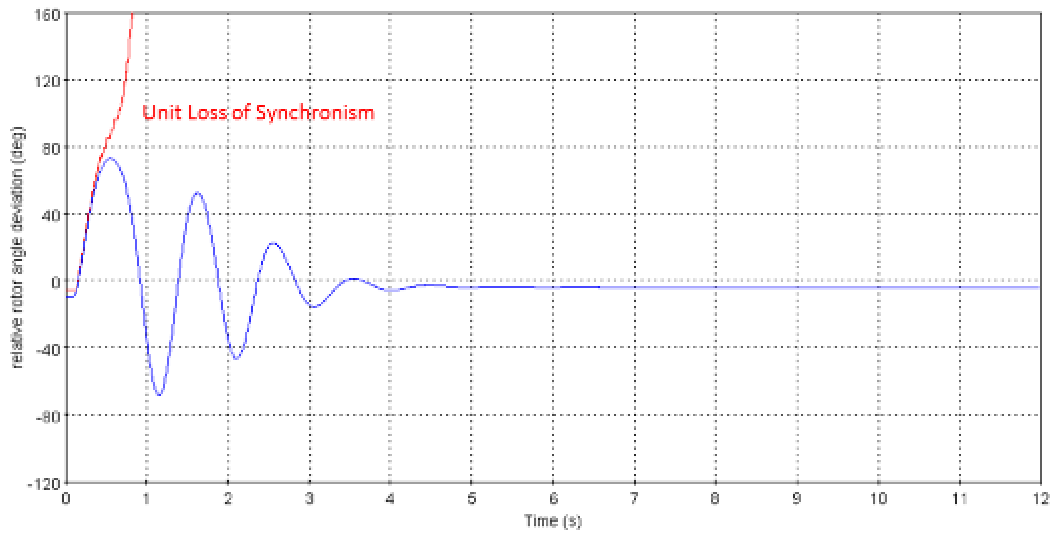

Figure 2.3: Example of Unit Instability

On the other hand, some transient instability can result in widespread system instability and uncontrolled separation. Certain critical contingencies under stressed conditions may result in interarea transient instability where coherent groups of generators lose synchronism with other parts of the system. This can have serious adverse impacts and widespread load loss. The operating conditions and the contingencies that cause the instability are well understood, planned accordingly, and monitored in real-time with an IROL.

Both Framework A and B account for unit(s) instability and exclude them from the establishment of IROLs (so long as they have no impact to the transmission system), and any unit instability would be managed with an SOL. Framework B explicitly states that unit instability that does not cause any adverse impacts to the transmission system does not warrant establishment of an IROL. Framework A focuses on load loss rather than generation loss, and therefore this aspect is not considered unless it has adverse impacts to neighboring RCs or other performance requirements established by the RC.

Key Finding:
Transient (angular) instability should be quantified and well understood; if the instability cannot be quantified, it warrants establishment of an IROL. Transient instability may or may not have an adverse impact to the BES, based on the system topology and criticality of generation to overall BES reliability. Generator loss of synchronism or other transient instability may not necessarily result in load loss, or the load loss may be minimal and can be restored quickly. Mitigating instability that does not have an adverse impact to the BES with an IROL versus an SOL has little reliability benefit unless the overall BES is at risk.

Recommendation:
Instability that is proved to have no adverse impact to the BES (i.e., does not result in tripping additional (or minimal) transmission elements or load) should not be mitigated with an IROL. Rather, an SOL with appropriate operating plans should be used to return to operating conditions that mitigate the instability.

Bounded Cascading and Load Loss

The MEITF discussed at length the existing definition of cascading, and the challenge with including “widespread” in the definition since it leaves the application of the definition up to interpretation. The MEITF proposed a definition, shown below, that addresses this issue and clarifies the phenomena of cascading.

Cascading: The uncontrolled successive loss of System Elements triggered by a Disturbance.

Using this definition, it is necessary to clarify the types of cascading that can be managed with an SOL (from a risk perspective) versus the types of cascading that warrant establishment of an IROL, and those operating limits should be established accordingly. The MEITF believes the most appropriate approach is to either define this in the FAC Standards requirements or leave it up to the SOL Methodology of each RC. However, it is acknowledged that some consistency in methods across all RCs would also gain consistency in developing IROLs to mitigate these conditions. For example, the overload threshold and its application to cascading methodologies is known to have inconsistencies among RCs across all interconnections.

Disallowing any amount of load loss caused by cascading is unrealistic and should not be the primary focus for establishing IROLs. Often times, a single subsequent overload may cause a minor load pocket to trip or tapped load off a transmission circuit to trip. These small loads tripping often help mitigate the sequence of cascading events, and often the cascading is bounded, studied, and contained. Entities are required to study this, and will use SOLs with operating plans to mitigate any overloads or violations in voltage criteria. The minor risk of cascading, with low probability of multiple thermal overloads with no operator action between contingencies, should not warrant establishing an IROL and therefore mandating potential use of pre-contingency load shedding.

Framework A allows for some flexibility in the RC establishing an IROL for cascading as part of its risk assessment. It allows some bounded amount of load loss caused by cascading before an SOL warrants becoming an IROL, and addresses the other cascading cases with SOLs and operating plans. On the other hand, Framework B does not allow any load loss as a result of cascading, and warrants establishing an IROL in all cases of load loss.

Key Finding:
The definition of cascading that currently uses the term widespread creates ambiguity on how it gets practically applied. A definition that eliminates this term is proposed by the MEITF. Some determination of acceptable versus unacceptable levels of cascading is therefore required to gain consistency across RCs for use in developing SOLs versus IROLs. Allowing some amount of load tripping during cascading is reasonable due to minor load pockets and tapped loads tripping during bounded, contained, pre-studied conditions.

Recommendation:
Any future revisions by a FAC Standards SDT should consider updating the cascading definition in the NERC Glossary of Terms. Subsequently, any revisions to the FAC Standards requirements (or specified in the RC SOL Methodology) should then specify what is considered acceptable versus unacceptable cascading for purposes of IROL establishment. Some degree of cascading that is bounded, studied ahead of real-time operation, and proved to be contained should not warrant establishment of an IROL. Minor load loss caused by cascading should be acceptably managed through SOLs rather than through the use of an IROL.

Pre-Contingency Load Shedding

In many cases, actions taken to mitigate an SOL exceedance in the post-contingency state may improve reliability of load service since the risk of the contingency actually occurring is very rare and the post-contingency action can sufficiently address the reliability issue. Some phenomena have sufficient time for operators to react post-contingency (e.g., cascading), although others likely do not (e.g., transient voltage instability). However, once an IROL has been established, in accordance with IRO-009-2, Requirement R1, operator actions up to and including pre-contingency load shedding must be implemented to prevent and mitigate exceeding the IROL (and eliminating an exceedance within its IROL Tv), effectively precluding the use of post-contingency actions to mitigate issues (which would improve load service reliability).

Cascading is an example of a phenomena that likely could allow for post-contingency operator action over pre-contingency load shedding. The MEITF has provided numerous examples of situations where bounded cascading could exist under certain N-x operating conditions. Figure 2.4 shows a simple example of a local load pocket. If one 230 kV line is out-of-service, then contingency analysis shows overloading on the 115 kV line for potential outage of the other 230 kV line. The TP has decided, as appropriate and allowable in the NERC TPL-001-4[4] standard, to not construct a new transmission circuit to serve this small load pocket. Rather, during forced or planned maintenance outages (which are already reduced and managed around peak conditions accordingly), the operator has chosen to take a risk of potential cascading that would only sever the load pocket from the rest of the BES and result in a small amount of load tripping.

[4] The proposed NERC Reliability Standard TPL-001-5 being drafted will account for planned maintenance outages. However, the concept of allowing load shedding after the second outage in an N-1-1 (after the maintenance outage is taken) remains.

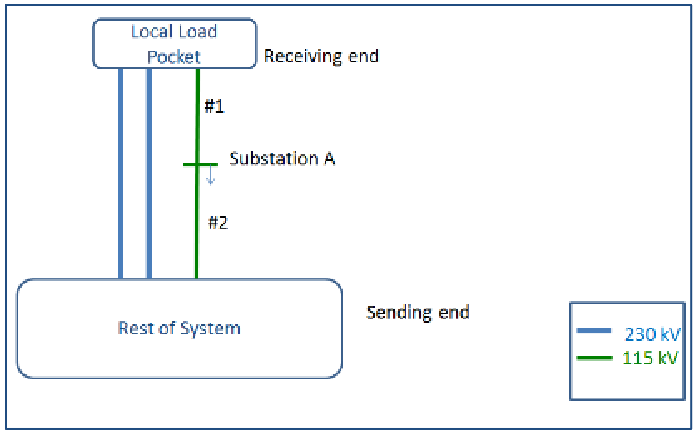

Figure 2.4: Example Cascading System

In this example, an SOL is established and operated to regardless of whether an IROL exists. However, if an IROL were established (that is, if the SOL were considered an IROL), then pre-contingency load shedding may be necessary to mitigate the potential overload of the 115 kV circuit if one of the 230 kV lines is out of service. Again, while the operator takes these outages during conditions where these potential overloads are minimized, some situations may warrant taking these outages when the overload could exist if the contingency were to occur (e.g., forced outages, prolonged maintenance outages). Assume the 115 kV line is overloaded to 120% in RTCA with one of the 230 kV lines out for maintenance. To mitigate this RTCA post-contingency violation, 10 MW needs to be reduced in the load pocket, and all other potential operator actions have been exhausted. The operator knows that if the overload occurs, the time-overcurrent characteristic of the line provides some time less than 15 mins for the operator to take action (yet knows that this is likely around 5 minutes). The operator feels comfortable that he/she can shed 10 MW of load post-contingency if the contingency were to occur, rather than pre-emptively trip the 10 MW prior to the contingency occurring. This improves reliability of load service and addresses the reliability issue accordingly. These types of actions should be allowable rather than requiring pre-contingency load shedding. In scenarios where a there is no time to take post-contingency actions, and a contingency of the remaining 230 kV line would be expected to result in the tripping of the remaining 115 kV line resulting in loss of the contained load pocket, the operators should be allowed to perform the risk assessment and make the decision of whether or not to shed load pre-contingency or to risk the loss of the load pocket should the contingency occur.

Key Finding:
Pre-contingency load shedding is not the most appropriate action to mitigate potential violations in reliability criteria, and may result in a degradation in reliability of load service. In some situations, post-contingency operator actions can suffice to eliminate the potential risk (e.g., cascading in some cases) without requiring the use of pre-contingency load shedding. Further, studies may prove a contained amount of load loss with no impact to the remaining BES, and should also suffice without taking pre-contingency action.

Recommendation:
When the load loss amount is proved to be contained (and possibly below some acceptable level), post-contingency load loss or load tripping may be sufficient and may also improve overall reliability of load service to end-use customers. These situations should not necessarily require the use of pre-contingency load shedding and therefore may not warrant the establishment of an IROL.

Uncontrolled Separation Analysis Considerations

As part of developing the *Reliability Guideline: Methods for Establishing IROLs*, the MEITF discussed the difficulty of analyzing uncontrolled separation. In many cases, uncontrolled separation takes the form of instability (either local or widespread) or cascading, depending on how quickly the phenomena occurs. For example, a sequence of overloads may result in a portion of the system separating, which is considered cascading. If no further cascading risk exists, this is considered a bounded cascade even if some portion of load is tripped. On the other hand, a voltage collapse or transient instability may cause a part of a load pocket or generator(s) to trip off-line. Both of these cases could be considered uncontrolled separation, yet (as previously described) could potentially be managed by an SOL due to their proven containment.

It becomes challenging to analyze uncontrolled separation in many situations since the reliability studies used to establish or set SOLs and IROLs use a pre-determined set of contingencies and operating conditions. Any known actions (e.g., protective relaying, remedial action schemes, and safety nets) are modeled and studied accordingly, and considered controlled actions. Therefore, any separation of load or generation should not be considered uncontrolled separation in these cases.

Some regions have known system instability conditions that could be considered uncontrolled separation, where large portions of the BES may separate from the rest of the BES. Other areas do not have these issues, and struggle with how to apply the definition of uncontrolled separation to their systems. It seems appropriate to keep uncontrolled separation focused on large portions of the BES rather than individual load buses or load pockets that could get separated for certain contingency under specific operating conditions.

Key Finding:
Applying the definition of uncontrolled separation is often challenging for study engineers since reliability studies use known contingencies and operating conditions. Establishing IROLs for uncontrolled separation resulting in small load pockets or generators that have no adverse impact to the BES can be problematic.

Recommendation:
Uncontrolled separation should focus on large portions of the BES separating from the rest of the BES. These conditions are well understood in the regions that have these potential issues under certain operating conditions, and IROLs are established accordingly. However, it is not appropriate to apply this concept to smaller load pockets or individual generator(s).

Alignment Issues between Planning and Operations

Table 1 of TPL-001-4 provides the planning events that must be studied and their performance requirements. For all planning events instability, cascading, and uncontrolled separation shall not occur. If any of these phenomena occur due to a planning event, planners must develop a Corrective Action Plan to resolve the performance deficiency (R2.7.1). The Corrective Action Plan may include operating procedures such as the use of IROLs or SOLS. R1 states that items in the Corrective Action Plan must be included in the system models that represent normal system conditions, category P0. Therefore, any IROL or SOL developed as part of a Corrective Action must not reduce load or interrupt firm transmission service pre-Contingency or it would violate the performance requirements for category P0. Otherwise, it is allowable for planners to use and model operating limits that if violated would result in instability, cascading, and uncontrolled separation for the next P1-P7 event. Although not currently required by the NERC standards, these limits should be communicated to the RC for them to evaluate and possibly establish IROLs. Additionally, planners are not permitted to shed load following a single outage in order to meet system performance requirements for the next outage. Table 1 shows that the initial conditions for P3 and P6 events are the loss of a single BES facility with system adjustments and footnote 9 states that the adjustments must not include non-consequential load loss.

Table 1 of TPL-001-4 also states that facility ratings must not be exceeded and planned system adjustments are only allowable if they can be executed within the time duration applicable to the facility ratings. If the system remains within short-term facility ratings then operating procedures involving post-contingency actions can be used. However, if the highest facility rating for a given facility is exceeded then post-contingency operating procedures cannot be used. Any pre-contingency operating procedures could include the use of operating limits; however, they must not include reductions to load or firm transmission service.

While operational studies that determine SOLs and IROLs stress the study parameters to cover for the worst case scenarios, in planning studies that might not be the case. TPL-001-4 Requirements R2.1.4 and R2.4.3 state that "Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response." However, Requirement R2.7 states that "Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3." Therefore, the sensitivity studies may identify potential issues in the planning horizon but CAPs do not need to be developed to address those issues before the studied conditions become a reality in the operations horizon.

If operating conditions are similar to the normal system conditions, represented by category P0 in the planning assessment, then the system is operating in the same state that it was planned for and the next P1-P7 contingency will not result in instability, uncontrolled separation, cascading, exceedance of facility ratings, or violation of voltage limits. However, operating conditions often vary significantly from planned conditions for three common reasons:

1. Planning studies generally do not capture multiple facilities out-of-service pre-contingency
2. RCs typically stress the system beyond planned conditions to determine SOLs/IROLs
3. RCs may not utilize the same operating procedures that planners developed in their Corrective Action Plans

From an operating perspective, the next single contingency represents an N-1 scenario, regardless of how many transmission or generation outages are already in effect. This would be equivalent to an initial condition represented by N-X. In planning assessments, only known outages with duration of at least six months are included in planning models. This results in a relatively small number of outages in the P0 case, compared to the number of facilities that typically unavailable on any given day. As a result, RCs are often required to operate to events that exceed what the system was planned for. Note that planning assessments may include extreme event studies that include a larger number of facilities out-of-service pre-contingency; however, planners typically do not develop Corrective Action Plans for extreme events.

RCs perform studies designed to stress the system in order to establish SOLs/IROLs. Planners may perform similar sensitivity analyses and instability, uncontrolled separation, and cascading are more likely to result from P1-P7 events in these conditions. However, R2.7 states that Corrective Action Plans do not need to be developed solely to meet the performance requirements from a single sensitivity case. Therefore, planners may choose not to develop any Corrective Action Plans, including using operating limits, to resolve identified performance deficiencies.

TPL-001-4 R2.7.1 requires planners to develop Corrective Action Plans, which may include operating procedures, to resolve performance deficiencies. These operating procedures must be included in the base case representing normal system conditions, category P0. Currently, there are no NERC requirements for these procedures to be reviewed or approved by the RC. This is particularly problematic when Corrective Action plans use operating limits or other pre-contingency operating procedures to prevent instability, uncontrolled separation, or cascading for the next contingency. If the RC does not perform these pre-contingency actions, they will be operating in a different state from what the system was not planned for.

When an IROL is established, the RC may have no options other than to drop load pre-contingency to prevent instability, cascading and uncontrolled separation. Similarly, when an SOL is established, the RC may need to decide between dropping load pre-contingency or exceeding facility ratings for the next contingency is warranted. Contrastingly, planners are prohibited from dropping load pre-contingency, excluding for situations beyond their control as described in R2.7.3. The MEITF does not consider this to be an alignment issue since the RC may need to operate to more severe events than what TPL-001-4 requires and the planner always has options beyond dropping load pre-contingency; whereas, the RC may not. However, the MEITF does believe that enhanced coordination between planners and the reliability coordinator would be beneficial during the development of corrective action plans that utilize operating procedures. There may also be benefits in coordinating the sensitivity studies that are performed in planning assessments with the studies used to determine IROL/SOLs in the operating horizon.

Key Finding:
The system is planned to meet the performance requirements specified in Table 1 of TPL-001-4 while serving all firm load and including all known firm transmission commitments. If the system is operating the same condition that it was planned for, category P0, there will be no instability, uncontrolled separation, cascading, exceedance of facility ratings, or violation of voltage limits for the next contingency. However, since operating conditions often vary from planned conditions, the RC may need to establish IROLs that were not identified in the planning horizon. The RC may shed load pre-contingency to remain within those IROLs; whereas, the planner is prohibited from shedding pre-contingency load. This is logical since the RC may be in an operating condition more severe than the events the system was planned for. However, enhanced coordination on sensitivity studies and operating procedures used in planning and operating analyses could reduce differences between the system conditions studied by the planners and the RC.

Recommendation:
A future SDT should consider how the TPL and FAC standards work in concert related to establishing IROLs versus developing corrective action plans to address reliability criteria in the planning horizon. Consideration should be given to the methods planners employ when utilizing operating procedures as part of the corrective action plans.

Contingency Selection

Requirement R5 in the proposed FAC-011-4 standard states that RC shall identify in its SOL Methodology the contingencies for use in determining stability limits and in OPAs and RTAs, and includes:

- Defined N-1 contingencies
- Additional N-1 or multiple contingencies
- Additional N-1 or multiple contingencies provided by the PC in accordance with FAC-015.

A potential issue (lack of clarity and inconsistency) arises in how those selected contingencies get applied in the studies performed in the OPAs, RTAs, and in establishing stability limits. In particular, it is not clear in the current or proposed standards whether the full set of selected contingencies need to be applied to both SOLs and IROLs, or if different sets of contingencies can be selected by the RC. For example, RC 1 may use credible multiple contingencies for establishing SOLs only while RC 2 may use credible multiple contingencies for establishing IROLs just like SOLs.

A potential solution to this issue in the new proposed FAC-011, Requirement R5, is to specify how those contingencies are intended to be applied to both SOLs and IROLs. Another solution is to be explicit in allowing the RC flexibility in how contingencies are selected. Either way, this should be made clear in future standards revisions. The MEITF believes that the RC should have flexibility to perform a risk assessment to determine the contingencies that should be operated to for SOLs and for IROLs. The SOL Methodology should explicitly describe in detail that N-1 contingencies should apply to SOLs and IROLs, and should also describe the method for selecting credible multiple contingencies for SOLs and IROLs.

Key Finding:
RCs used different methods for applying selected contingency events to the studies for establishing SOLs and IROLs. The FAC SDT's current draft of FAC-011-4 does not specify how the RC's contingency list are intended to be applied in studies – i.e., are they being applied to assess the establishment of a SOL or an IROL.

Recommendation:
Proposed revisions to FAC-011 should address this ambiguity in how selected contingency events in FAC-011 and should be documented in the RC's SOL methodology. Requirement R5 is applied to studies to establish or set SOLs and IROLs. In particular, the RC should have flexibility in determining how selected contingencies are applied for SOLs and IROLs based on a risk assessment.

Establishing IROLs for Expected Operating Conditions

It should be made very clear in any FAC standards revisions that IROLs are established for expected operating conditions. IROLs should be established prior to real-time operation and the limit values may be updated as real-time conditions near or during real-time operations. TOPs and RCs are required to study these expected operating conditions ahead of real-time operation, so this paradigm that IROLs should be established in this timeframe (or earlier) aligns well with the study process.

Currently, there are no requirements related to how and when studies are performed to establish or identify operating limits for N-1-1 conditions. This may lead to situations where the RC is in an "unknown operating state" immediately following an actual contingency occurring. The potential reliability gap for operation in an "unknown operating state" was created by the retirement of TOP-004-2 Requirement 4 (March 31, 2017). While suitable for the pre-contingency operation and expected operating conditions, the OPA and RTA concepts used in the development of TOP-001-4 Requirements 12, 13 and 14 do not adequately cover for unexpected operating conditions and the post-contingency operation as described here. The RC knows that they were in an N-1 secure operating state before the contingency (no violation of emergency limits post-contingency). However, the RC must now assess whether they are in a new N-1 secure operating state. This N-1-1 condition is not required to be studied before the first N-1 by the existing standards, so inherently an "unknown operating state" could exist as soon as any forced outage occurs on the BPS. Some guidance or framework is needed to require additional studies to be performed to study multiple contingencies deep for known stability limits.

For example, assume the system is operated in an N-1 secure operating state (within all SOLs and IROLs for pre- and post-contingency conditions). A contingency occurs and, as expected, the system is within all its emergency limits. Now the system is operated in a new "N-0" initial state with that element out of service that likely was not studied ahead of time. Just after the contingency event occurs, subsequent real-time assessments are based on this new N-0 state and may indicate unacceptable N-1 system performance until adjustments are made. The question arises of how to handle this situation with regard to IROL establishment. Most RCs study multiple contingencies deep in offline studies (e.g., seasonal studies, special assessments, and some OPAs) for these purposes so they are prepared for outage conditions. However, as soon as the contingency occurs, the system is expected to be returned to an operating state that is within all SOLs and IROLs for pre- and post-contingency operating conditions. The SOL or IROL limit may need to be updated (particularly for stability cases) and the system will have to be readjusted.

Unforeseen operating conditions (extreme unexpected demand levels, unforeseen forced outage conditions, etc.) may configure the system in an operating condition that was not pre-planned or pre-studied. In these cases, the focus should not be on establishing a new IROL (or SOL) within a specified period of time. The focus should be on returning the system to a state that the system operator knows is safe for the next single contingency or credible multiple contingency. This may require drastic action, up to and including load shedding, and many RCs refer to this as "IROL-like conditions" where urgent action is taken to return to a state where the system performs acceptably for the next contingency event. However, these relatively unexpected and rare operating conditions should not necessarily lead to the constant establishment and removal of IROLs. Operating plans should be developed to account for these types of conditions, and those plans should include relatively drastic action to return to expected or studied conditions fairly quickly.

The MEITF discussed this at length, and proposes that stability-related SOLs (which could be IROLs) that have been defined in the OPA (or pre-defined some time before) should be studied for ensuring N-1 security for after the contingency occurs. This ensures that operating plans are feasible after the first contingency were to occur to bring the system back to a secure operating state. For stability-related SOLs and IROLs, this is critical since there may not be a time duration associated with the post-contingency risk. For any N-1 or credible N-2 contingencies that could result in instability, the N-1-1 and N-2-1 conditions should also be studied to develop robust operating plans.

Some RCs have online stability tools that can do this automatically (as part of the RTA). If these tools are not available, or the instability conditions are too complex, the RC should be studying multiple layers deep to be prepared for the post-contingency operating conditions and timely system readjustment through pre-determined operating plans.

Both Frameworks A and B account for this concept. However, Framework B explicitly calls this concept out by using "expected" system conditions. The MEITF believes that any framework should make clear that IROLs are established for expected conditions and then attempt to define what expected conditions may include such as studying multiple layers deep for contingency analysis.

Key Finding:
Unforeseen conditions (e.g., forced or urgent outages) may arise where the unplanned or unforeseen operating conditions do not match the planned, expected conditions. In those cases, priority is given to returning relatively quickly to a state where the system performs acceptably for the next contingency event. On the other hand, IROLs and other SOLs are studied and set accordingly to expected operating conditions (e.g., elements out, load levels, transfers). The limit values may be updated as real-time approaches, yet are typically set in advance.

Recommendation:
It should be made very clear in any FAC standards revisions that IROLs are established for expected operating conditions. IROLs should be established prior to real-time operation and the limit values may be updated as real-time conditions near or during real-time operations. At the very least, the time allowed to proceed with corrective actions should be different for planned conditions (“N” system) versus following a contingency (“N-1” system) to allow considerations for risk mitigation and probability of occurrence of a second contingency. RCs should study multiple contingencies deep, particularly for stability-related SOLs and IROLs where the post-contingency risk is greater.

Understanding Risk

The MEITF, in its first framework that was presented to and approved by the NERC PC and OC, recommended that an upper threshold for load loss be used to set a bookend for which IROLs should always be used to protect reliability of the BES. The MEITF also proposed that below that threshold (i.e., 2000 MW) a risk framework be applied by the RC to determine on a case-by-case basis whether an IROL should be used or whether an SOL would suffice. That framework stated that the risk assessment, at a minimum, would include the following considerations:

a. Amount of pre-contingency load shedding necessary
b. Resulting impacts to neighboring Reliability Coordinator Areas
c. Nature of the load (e.g., economics, criticality, geographic region, etc.) at risk
d. Restoration plans and estimated time to restore the affected load at risk
e. Risk of contingencies more severe than single contingency events

The MEITF membership agreed that there is a balance between putting some amount of load at risk of instability, uncontrolled separation, or cascading versus putting that load at risk of pre-contingency load shedding if an IROL is established. The preceding sections describe the challenges with this balance; however, it ultimately comes down to the risk tolerance of the RC and its stakeholders. In any case where the instability, uncontrolled separation, or cascading cannot be proved to be contained, the RCs unanimously believed that an IROL should be established to protect the BES. However, they also believed that each case is unique based on the attributes described above, and that each case warrants a risk assessment to determine whether an SOL can be used (risking that actions may not be completed within 30 minutes and actions may not include load shedding) or an IROL should be used (risking that load is shed pre-contingency for a contingency event that may never occur).

Framework A, developed by the MEITF, provides flexibility to the RC in establishing IROLs that have a relatively higher impact to overall interconnection reliability (while still establishing SOLs to protect against any instability, uncontrolled separation, and cascading). Framework B uses a zero risk tolerance and does not allow for any risk assessment. Through any means available, including pre-contingency load shedding, Framework B does not allow for any load loss caused by instability, uncontrolled separation, or cascading. Framework A enables the RC to manage risk for each specific situation whereas Framework B attempts to eliminate risk while specifying a fairly rigid, inflexible framework for establishing IROLs.

Key Finding:
Any consideration for whether an SOL should be an IROL includes some degree of risk assessment by the RC, otherwise all SOLs related to instability, uncontrolled separation, and cascading would be considered an IROL irrespective of the severity of impact or the relative risks involved on a case-by-case basis. Risk assessment provides the RC with flexibility while ensuring some degree of consistency across all RCs.

Recommendation:
Some degree of risk assessment should be allowed by the RC to provide flexibility in the way that IROLs are established. Requiring that *all* instability, uncontrolled separation, and cascading be mitigated with an IROL should be avoided because it will result in substantially more pre-contingency load shedding for instability, uncontrolled separation, and cascading conditions that are known to be bounded, contained, and have minimal risk to the overall BES.

Recommended Analytical Methods

The MEITF developed the *Reliability Guideline: Methods for Establishing IROLs*, which provides technical reference material and guidance for the analytic techniques and approaches for studying instability, uncontrolled separation, and cascading. The guideline is independent of any IROL framework or potential revisions to NERC Reliability Standards. It does not focus on what should be considered an IROL versus an SOL. Rather, it focuses on the analytical methods for studying the various types of phenomena in sufficient detail such that appropriate decisions can be made by the RC. The techniques presented in the guideline should ideally be considered by RCs when developing their SOL Methodologies. Industry should find the material presented useful in understanding assessment techniques for instability, uncontrolled separation, and cascading. Future SDT efforts may also use this guideline as a reference for consideration when developing requirements related to establishing IROLs. Many of the analytical methods presented in the guideline can be applied to other studies performed in the planning and operations horizons, including (but not limited to) stability studies performed for TPL planning assessments and CIP-014 risk assessments.

Key Finding:
The analytical techniques used for studying the impacts of instability, uncontrolled separation, and cascading are not well documented across SOL Methodologies. The *Reliability Guideline: Methods for Establishing IROLs* developed by the MEITF seeks to fill that technical gap and provide relevant guidance for the industry. The guideline provides technical information independent of any IROL framework or potential revisions to NERC Reliability Standards.

Recommendation:
The techniques presented in the guideline should be considered by RCs when developing their SOL Methodologies.

Separation of IROLs from Use in Other Reliability Standards

The MEITF is aware that the FAC SDT is proposing modifications to other NERC Reliability Standards to eliminate the linkage between IROLs and other activities unrelated to the operations horizon (i.e., the specific CIP, FAC, IRO, and TOP NERC Reliability Standards). In the current body of standards, IROLs are used as a mechanism to determine applicability of requirements in several other standards including CIP, vegetation management, and protection and control. The proposed changes to these standards are driven by the proposed retirement of FAC-010, where IROLs would no longer be established for the planning horizon. The SDT has the opinion that IROLs are not the appropriate mechanism for determining applicability of other standards. Rather, revision to those other standards can replace the use of IROLs with the studied phenomena (often in the planning horizon) – e.g., identifying instability, uncontrolled separation, and cascading and linking those.

The proposed revisions to the FAC standards by the SDT are supported by the MEITF, and focus on establishing IROLs in the operations planning and day-ahead time horizons only. These IROLs may be situation-specific or even temporary based on the impending system conditions. Because of the dynamic nature of IROL establishment, the identification of facilities applicable to CIP, vegetation management, and protection and control is more appropriately based on long-term planning studies where their criticality to the System can be determined in a more consistent and practical manner.

The MEITF supports this approach and believes this may lead to a willingness to use operating limits more appropriately since there would be less external ramifications unrelated to real-time operation.

The frameworks presented here are somewhat irrelevant to this topic. Both framework would establish IROLs, and those IROLs could be linked to other NERC Reliability Standards if those linkages are not removed. It is worth reiterating that Framework B would result in substantially more IROLs, many of which would be temporary. This will cause significant confusion for the other NERC Reliability Standards in how those get applied.

Key Finding:
IROLs are used in a number of other NERC Reliability Standards, which can create additional burdens and compliance obligations when establishing IROLs. These links may not be necessary and have possibly led to IROLs not being used temporarily, as they should be, due to these linkages. It is possible that these linkages have discouraged the establishment of IROLs altogether.

Recommendation:
MEITF supports the efforts by the FAC SDT to propose revisions to NERC Reliability Standards that eliminate the link between IROLs and the other NERC Reliability Standards that are not related to real-time operations (i.e., specific CIP, FAC, IRO, and TOP NERC Reliability Standards). Those proposed revisions allow for IROLs to be established and used solely for operating purposes. This separation should result in IROLs being used more appropriately in temporary situations such as maintenance outages. The SDT has proposed revisions to the standards to ensure that there are no reliability gaps, and that the intent of those other standards can be fulfilled.

Chapter 3: Illustrative Examples of Considering IROLs

This chapter shows illustrative examples across all interconnections where the considerations described in this report are applied to actual systems. Each example provides either qualitative or quantitative examples of how the entity is considering the specific system in its determination of establishing an IROL or not.

Illustrative Example 1 – ISO-NE

This example uses an actual load pocket in the ISO-NE footprint. Figure 3.1 shows a simplified oneline diagram of the network under consideration. The local network can be prone to voltage collapse during outage conditions, which has been proved to be local and contained in nature. This example shows the risk analysis performed to determine the prudence of establishing an IROL versus a stability-related SOL.

The number of line outages per mile per year for this area has been analyzed by ISO-NE, and determined to be around 0.01 outages/mi/year. This statistical information is then applied to each of the lines connected the load pocket, as shown in Table 3.1. The annual initial outage likelihood (likelihood the line will be out pre-contingency) is then determined for each line based on its length. From that information, ISO-NE determined which line would cause a collapse in the local pocket, and the annual probability of the contingency causing a collapse is determined.

This collapse situation is only a possibility under certain loading conditions, and the potential collapse of the pocket is only at any type of risk about 25% of the time (this is an overestimation of the actual risk). From this information, the annual exposure of collapse is calculated based on the likelihood of loading and the probability of outage of lines that would cause a collapse. The total exposure is calculated, which is converted to the total hours of load at risk.

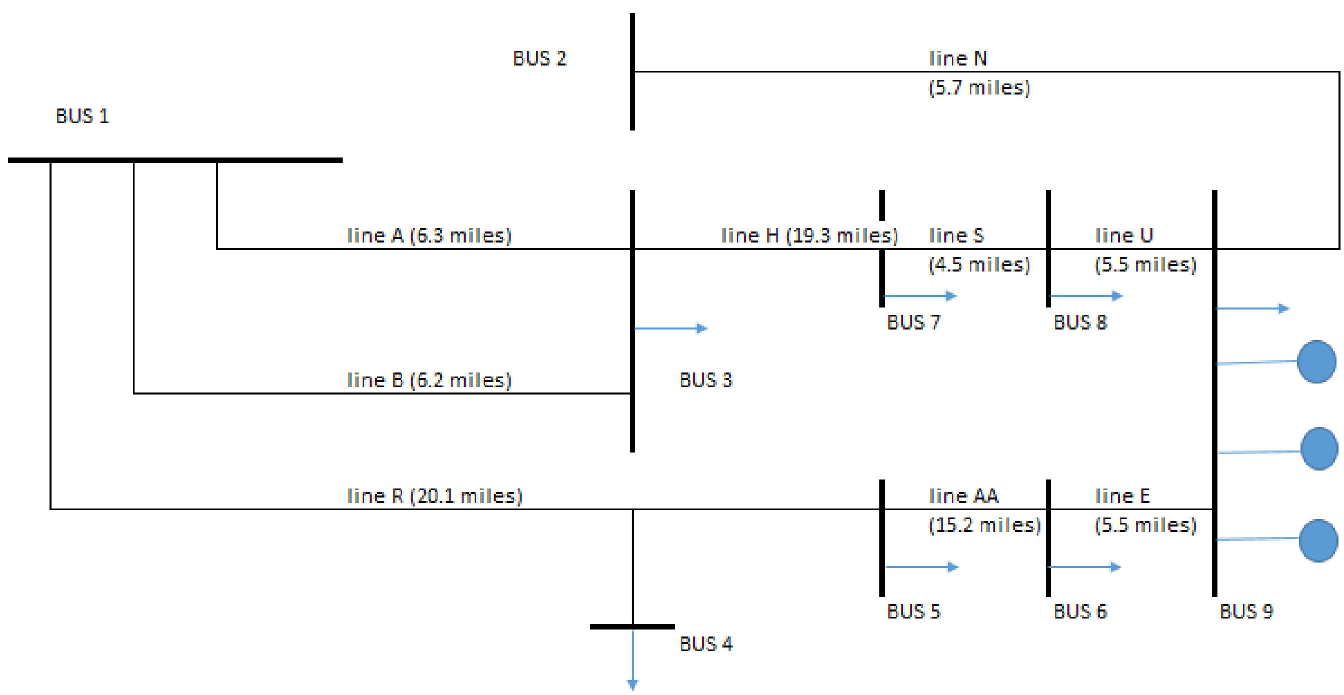

Figure 3.1: 345 kV Bus Configuration

Table 3.1: ISO-NE Quantitative Outage Example						
Line	Length	Annual Initial Outage Likelihood	Line Causing Collapse	Annual Probability of Outage Causing Collapse	Likelihood at Load Level with Exposure	Annual Exposure
A	6.3	6.30%	N	5.70%	25.00%	0.090%
B	6.2	6.20%	N	5.70%	25.00%	0.088%
R	20.1	20.10%	N	5.70%	25.00%	0.286%
H	19.3	19.30%	N	5.70%	25.00%	0.275%
S	4.5	4.50%	N	5.70%	25.00%	0.064%
AA	19.2	19.20%	N	5.70%	25.00%	0.274%
U	5.5	5.50%	N	5.70%	25.00%	0.078%
E	5.5	5.50%	N	5.70%	25.00%	0.078%
N	5.7	5.70%	R	20.10%	40.00%	0.458%
				Total Exposure (w/ No Gen Use)		1.692%
				Total Annual Hourly Exposure		148.2

Based on this information, the following comparison is made between the following scenarios:

1. An IROL is established and load must be shed pre-contingency to mitigate the contained[5] voltage instability from occurring. (i.e., Framework B)
2. A stability-related SOL is established and load is not shed pre-contingency; there is some load at risk of voltage instability in the local load pocket. Realistic outage information is used. (i.e., Framework A)
3. A stability-related SOL is established and load is not shed pre-contingency; there is some load at risk of voltage instability in the local load pocket. Conservative outage information is used. (i.e., Framework A)

The following three examples using the scenarios listed above illustrate how it is not prudent to address this local voltage instability with the establishment of an IROL and pre-contingency load shedding required by Framework B. Rather, the issue should be addressed with a stability-related SOL that uses all available mitigating actions to eliminate the SOL exceedance (except pre-contingency load shedding) as allowed by the MEITF recommended Framework A. The amount of unserved energy to the load pocket is orders of magnitude higher when an IROL is established compared with the situations where a stability-related SOL is established to protect the load pocket.

Example A: Realistic Comparison

Assume that the following information is used to statistically compare the amount of annual energy loss between the establishment of an IROL (#1 above) and establishment of an SOL (#2 above) using realistic data (see Table 3.2). In this case, it is assumed that the amount of pre-contingency load shedding required to remain below the IROL is 30 MW on average. In this example, the generation in the load pocket is not available (e.g., has been recently retired) – therefore, generation redispatch is not considered in this case. The restoration time if voltage collapse occurs is 3 hours. The load at risk of collapsing is 160 MW.

[5] The voltage instability was proved with detailed studies to be contained to a local area of approximately 160 MW of load at risk.

Table 3.2: ISO-NE Quantitative Outage Example	
Variable	**Value**
MW load shedding required to remain below IROL	30 MW
Load restoration time if collapse occurs	3 hrs
Load at risk of collapse	160 MW

Table 3.3 shows a side-by-side comparison of the amount of annual energy lost (purposefully shed due to the establishment of an IROL, in alignment with Framework B) or possibly at risk (if the contingency were to occur when operating past the SOL, in alignment with Framework A). It is absolutely apparent in this realistic example that the enforcement of an IROL for this local load pocket leads to significantly more annual energy lost than taking the risk of the critical contingency occurring during operating conditions where the voltage collapse risk exists.

In this case, since the amount of load at risk is proved by studies to be contained to a local load pocket of only 160 MW, the RC chooses to not establish an IROL in this situation. Rather, an SOL is established and all operating action is taken (other than pre-contingency load shedding) to mitigate the SOL exceedance.

Table 3.3: Scenario A Side-by-Side Comparison					
IROL Established (Scenario #1) – Framework B			**SOL Established (Scenario #2) – Framework A**		
Value	Units	Description	Value	Units	Description
148[6]	hrs	Hours above load level that would exceed IROL	3	hrs	Hours to restore load following collapse
100	%	Likelihood of load tripping	1.7	%	Likelihood of load loss due to collapse
30	MW	MW that must be shed to remain below IROL	160	MW	MW that would be lost during collapse
4447	**MWh**	**Expected at-risk load loss from enforcing IROL**	**8.2**[7]	**MWh**	**Expected annual at-risk energy due to exceeding SOL**

Example B: Ultra-Conservative Assumptions Comparison

This example uses the same setup as the previous example; however, ultra-conservative numbers (scenario #3 above) are used to show the impact it has on the at-risk load loss numbers. In this case, it is assumed that the amount of pre-contingency load shedding required to remain below the IROL is only 15 MW on average. The restoration time if voltage collapse occurs is 12 hours (extreme delays). The load at risk of collapsing is 300 MW (larger portion of load pocket, which is proven to not occur). The time of exposure to voltage collapse is increased from 25% to 100% (all hours of the year).

[6] This comes from multiplying the cumulative exposure to coincident outages that "take down the area" (i.e. cause collapse) times the total number of hours each year. For example, if the cumulative exposure was a 1% exposure, assuming no coincidence factor, then the total amount you would expect this to occur is 0.1 * 8760 or 87.6 hours a year.

[7] By adding in the hours for system restoration, the expected annual at-risk load is the likelihood of the event (1.7%) times the load at risk (160 MW) times the length of time it is out (3 hours), or .017 * 160 * 3 = 8.16 MWh.

Table 3.4: ISO-NE Quantitative Outage Example	
Variable	**Value**
MW load shedding required to remain below IROL	15 MW
Load restoration time if collapse occurs	12 hrs
Load at risk of collapse	300 MW
Number of line outages per mile per year	0.3
Likelihood at Load Level with Exposure	100%

With these assumptions, the likelihood of the collapse occurring increases to 6.1%. Table 3.5 shows again that establishing an IROL to protect against the local, contained voltage instability is not the prudent or reliable operating decision. In this case, even with conservative assumptions on the load restoration time, the probability of collapse occurring, and the impacted load pocket, the expected annual at-risk energy is an order of magnitude lower when a stability-related SOL is established compared with establishing an IROL. This is ultimately due to the fact that the IROL locks in pre-contingency load shedding for many hours of the year. Even though the amount of load shedding is relatively small, the frequency that this must occur is significant.

Table 3.5: Scenario A Side-by-Side Comparison					
IROL Established (Scenario #1) – Framework B			**SOL Established (Scenario #2) – Framework A**		
Value	**Units**	**Description**	**Value**	**Units**	**Description**
533	hrs	Hours above load level that would exceed IROL	12	hrs	Hours to restore load following collapse
100	%	Likelihood of load tripping	6.1	%	Likelihood of load loss due to collapse
15	MW	MW that must be shed to remain below IROL	300	MW	MW that would be lost during collapse
7992	**MWh**	**Expected annual at-risk energy from enforcing IROL**	**219**	**MWh**	**Expected annual at-risk energy due to exceeding SOL**

Example C: Realistic Comparison with Generation Redispatch

Let us again use the Example A realistic data obtained by the RC, except this time consider generation redispatch for mitigating the hours in which the IROL exceedance would occur. In this case, the local generation in the load pocket is assumed to be able to ramp up within 30 minutes (an optimistic assumption in some cases) to eliminate the IROL exceedance and eliminate the need for pre-contingency load shedding. Let us also assume that this results in the need for pre-contingency load shedding only 15 hours out of the year, as opposed to the 148 hours calculated using the outage probabilities. As in, about 90% of the time that the IROL is exceeded, generation redispatch can address the exceedance.

Table 3.6 shows the results of this comparison, and even in this case it is still not prudent to establish an IROL since it will result in about 20 times more energy being unserved compared to establishing an SOL and taking the risk of local voltage instability (proved to be contained).

Table 3.6: Scenario A Side-by-Side Comparison					
IROL Established (Scenario #1) – Framework B			SOL Established (Scenario #2) – Framework A		
Value	**Units**	**Description**	**Value**	**Units**	**Description**
15	hrs	Hours above load level that would exceed IROL	3	hrs	Hours to restore load following collapse
100	%	Likelihood of load tripping	1.7	%	Likelihood of load loss due to collapse
30	MW	MW that must be shed to remain below IROL	160	MW	MW that would be lost during collapse
450	**MWh**	**Expected at-risk load loss from enforcing IROL**	**8.2**	**MWh**	**Expected annual at-risk energy due to exceeding SOL**

Illustrative Example 2 – ERCOT

This example uses an actual looped network in the West Texas area of ERCOT where some renewable energy resources and heavy oilfield loads have developed in recent years. Figure 3.2 shows a simplified oneline diagram of the local area, which a significant number of tapped loads in the looped network. With the pre-contingency outage of any of the orange lines (two near the top and one at the bottom), the next contingency leaves the looped network connected to the rest of the BES through a single transmission line. These lines are older 138 kV, leaving a fairly weak network under outage conditions. This results in a local voltage collapse of the remaining radial load after the contingency occurs. This situation is only an issue when the solar PV resources are not generating (i.e., during the nighttime hours). The total load in this pocket is approximately 150 MW. ERCOT has proved by studies that the local load pocket collapses under these outage and operating conditions, with no impact to the remaining BES.

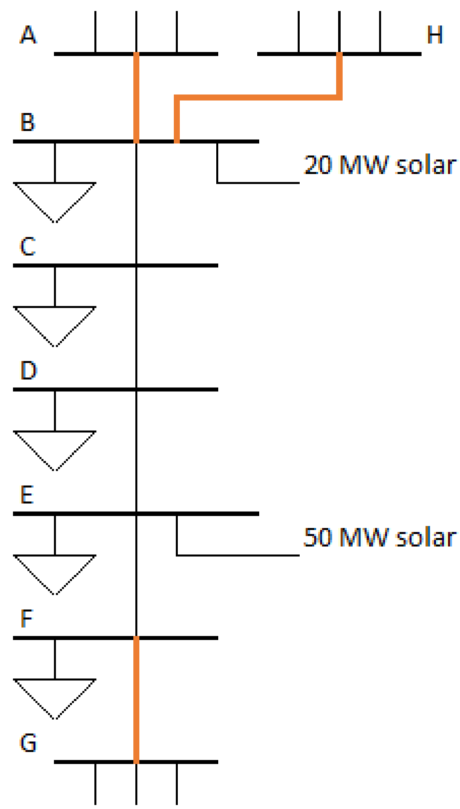

Figure 3.2: Example Network

Statistical outage information is not known for these circuits at this time. However, one could assume 8% outage rates for each of the transmission lines. The amount of load shedding needed to mitigate the local voltage instability is 20 MW under these conditions. Restoration time for any collapse situation is conservatively estimated at 3 hours.

Table 3.7 shows a comparison of the outage information for this network.

Table 3.7: ERCOT Quantitative Outage Example					
Line	Annual Initial Outage Likelihood	Line Causing Collapse	Annual Probability of Outage Causing Collapse	Likelihood at Load Level with Exposure	Annual Exposure
A-B	8%	H-B	8%	25.00%	0.320%
H-B	8%	A-B	8%	25.00%	0.320%
G-F	8%	A-B	8%	25.00%	0.320%
			Total Exposure (w/ No Gen Use)		0.960%
			Total Annual Hourly Exposure		84.1

A comparison of the amount of annual expected unserved energy for either establishing an IROL versus establishing a stability-related SOL is shown in Table 3.8. The results show the same conclusion as the ISO-NE examples. Locking in pre-contingency load shedding, as proposed by Framework B, to protect for a localized, contained collapse of a pocket of load (and generation) leads to more at-risk energy being unserved compared to taking the risk of the instability occurring as studied. In this case, ERCOT has chosen to establish a stability-related SOL with appropriate operating actions in place to mitigate the SOL exceedance. As proposed by Framework A, these operating plans do not include pre-contingency load shedding since the instability is relatively small and proven by studies to be local.

Table 3.8: ERCOT Looped Example Scenarios					
IROL Established			**SOL Established**		
Value	**Units**	**Description**	**Value**	**Units**	**Description**
84	hrs	Hours above load level that would exceed IROL	3	hrs	Hours to restore load following collapse
100	%	Likelihood of load tripping	1	%	Likelihood of load loss due to collapse
20	MW	MW that must be shed to remain below IROL	150	MW	MW that would be lost during collapse
1682	**MWh**	**Expected at-risk load loss from enforcing IROL**	**4.3**	**MWh**	**Expected annual at-risk energy due to exceeding SOL**

Illustrative Example 3 – ERCOT

This example uses a region of the ERCOT system that has a significant penetration of renewable energy resources, particularly wind power plants. Figure 3.3 shows a simplified oneline diagram of the area where instability is known to occur. Under outage conditions, the short circuit strength of the local network becomes significantly lower. This can lead to controls instability and the plants tripping offline when they are operating at relatively high active power output. With controls instability, due to the low short circuit strength in this area, the plant and turbine controls begin interacting with each other resulting in oscillations and chattering controls, which causes the plants to trip. The instability conditions of the power plants has been studied and proved to not impact other transmission facilities other than those connecting the generating resources to the BES.

These conditions do not occur for N-1 contingencies when all lines are in service. This issue arises when lines are out pre-contingency and then another contingency occurs (causing the short circuit strength to weaken drastically). TPL-001-4 allows for instability of a generator in simulation assuming it does not impact transmission system elements. However, it is unclear if this applies to only a single unit or multiple units so long as the transmission system is not impacted. The MEITF believes the interpretation of this should be multiple units so long as the transmission system is not impacted.

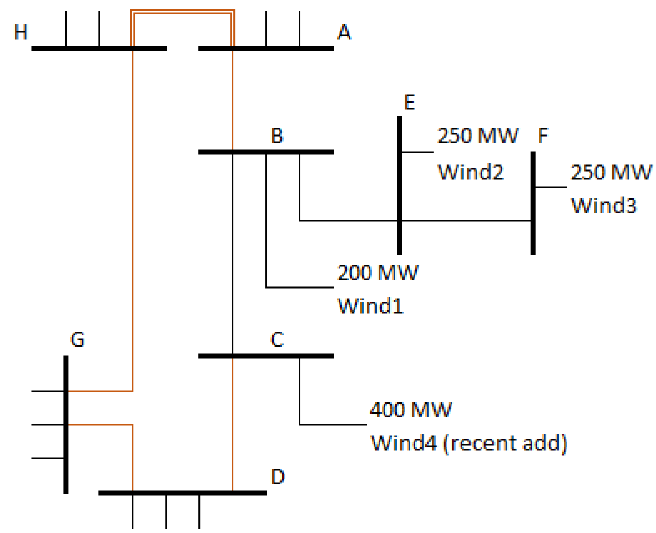

Figure 3.3: High Wind Pocket

This logic aligns with ERCOT operating experience and mentality that these unit instabilities should be permissible since they have no impact to the transmission system elements or other parts of the BES. The instability is localized in nature due to low short circuit strength at these buses. For this reason, in alignment with Framework A, ERCOT has established a stability-related SOL and appropriate redispatch is done to remain within the SOL. If Framework B had been utilized, because exceedance of the limit could have resulted in instability, even though the instability is bounded and localized, an IROL would have to be established. While generation redispatch to return within the defined SOL already occurs as part of the operating plans, taking these actions within 30 minutes should not always be required (may cause unreliable actions by the GOP, possibly including tripping).

Illustrative Example 4 – Bonneville Power Administration

There are two examples provided by BPA of local areas with instability or cascading issues, and a description of how those issues are managed.

Eastern Washington Load Service

Figure 3.4 shows a portion of the BPA and neighboring system, where red is 500 kV, blue is 230 kV, and black is 115 kV. Bell 115 kV also serves some radial load, about 100 MW during peak hours.

If the Bell 230/115 kV transformer is out-of-service during moderate to high demand in the area, the next N-1 (loss of Bea-NE 115 kV line) can potentially overload the Bea-Bell 115 kV line. Following the second outage, operators could take action to shed some of the 100 MW load at Bell to relieve the overload, or operators could trip the Bea-Bell 115 kV line. If the Bea-Bell 115 kV line is then tripped, analysis shows that local voltage collapse would occur at the Bell 115 kV bus. The entire 100 MW radial load served out of Bell would be lost, and no further overloads or low voltages occur on the rest of the system.

From a planning perspective, this N-1-1 scenario relies on 100 MW of non-consequential load loss as allowed by the NERC TPL standard, and no corrective action is necessary to meet performance requirements. A relatively small amount of load loss caused by the low probability N-1-1 contingency during only parts of the year does not justify an expensive transmission reinforcement in this scenario. The NERC TPL standard allows for this scenario for this reason.

From an operational perspective, if the Bell 230/115 kV bank is out-of-service, RTCA may show an overload on the Bea-Bell 115 kV line. Framework B requires that IROLs be established for any voltage instability. Thus, if an IROL were established, load shedding would be the only viable solution to mitigate the overload within 30 minutes, and would be initiated to eliminate the RTCA overload following the Bell 230/115 kV outage. This load shedding would prevent the loss of the bounded and localized 100 MW voltage collapse at Bell if the second outage were to occur. However, requiring a fraction of the 100 MW load to be shed following a single contingency (Bell 230/115 kV transformer in this example) to save the remainder of the 100 MW load if a second contingency were to occur (Beacon-Bell 115 kV line in this example) would result in significantly less reliable service from a risk perspective. The MEITF believes that no amount of loading shedding following a single outage is reasonable to prevent loss of 100 MW of load if the second contingency were to occur. It is more reasonable to utilize Framework A which would allow putting the full 100 MW[8] of load at risk due to the low probability of the overlapping contingencies occurring in conjunction with the known small amount of load that would be lost if that rare event were to occur. Therefore, forcing load shedding to occur to save 100 MW for a N-1-1 scenario, as would be required using Framework B, is not reasonable.

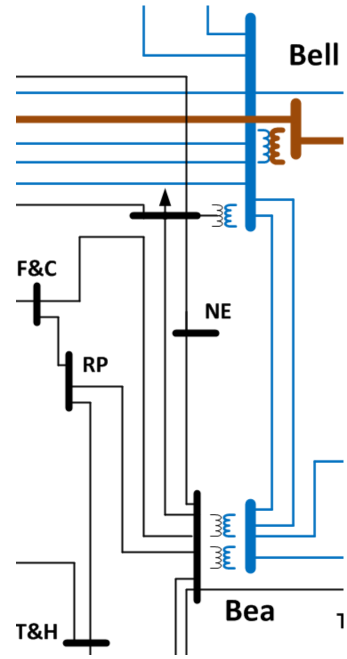

Figure 3.4: Example BPA System

Oregon Coast Load Service

Figure 3.5 shows the North Oregon coast system. The rectangles represent stations with circuit breakers. Black is 115 kV and blue is 230 kV. The dots represent tap points without circuit breakers. There are a large number of load taps on the 115 kV lines. There is a 230/115 kV transformer at Lew (upper left) and Til (lower left).

If the Lew transformer is out of service, the N-1 loss of the Dri-Ast 115 kV results in the Oregon coast load being served radially from Til. As a result, the Til-Ast 115 kV line can experience overloading and potentially trip. If the Til-Ast 115 kV line were to trip, ~100 MW of load would be lost. From a planning perspective, 100 MW of non-consequential load loss following a P6 event is allowable per the TPL standard and would not require a corrective action plan. From a planning perspective, allowing 100 MW of non-consequential load loss is also reasonable because the same amount of consequential load loss would occur for an N-1 Til-Ast line fault. In operations, around 5 MW of pre-contingency load shedding would be needed to prevent the line overload (post-contingency). There are no other operational actions to mitigate the overload. It does not seem appropriate to establish an IROL in this situation, where the overload would result in a small amount of load loss, nor does it seem appropriate to trip load pre-contingency which would be required by Framework B (to prevent "cascading resulting in load loss" or "voltage collapse"). If the N-1 Dri-Ast line contingency were to occur with the Lew transformer already out of service, the line would be overloaded to around 103% of its highest emergency rating. The operator has sufficient time following the contingency to take post-contingency actions to trip load which is allowed by Framework A. Performing this action pre-contingency results in degraded load service, and therefore an IROL is not warranted.

[8] To put 100 MW of load in perspective, BPA has some 115 kV and 230 kV lines which have close to 100 MW of load tapped off of them. For these, a simple line fault would result in 100 MW of consequential load loss.

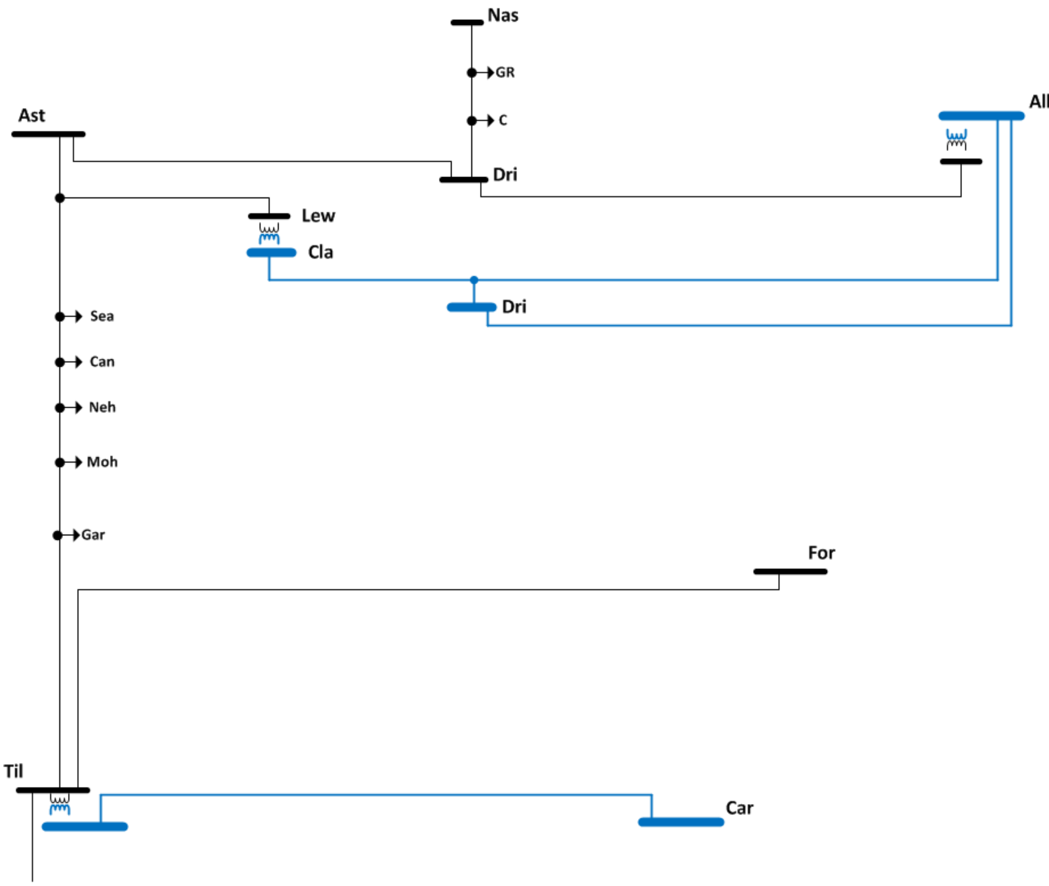

Figure 3.5: Oregon Coast System

Illustrative Example 5 – Hydro Quebec

This example illustrates the issues and implications of establishing an IROL for mitigating potential cascading of transformers and potential load pocket collapse due to voltage instability. Figure 3.6 shows a simplified diagram of the area being discussed. It is comprised of approximately 1900 MW of load at peak (mainly industrial load), 1500 MW of installed generation (mix of nuclear and gas), and HVDC converters that can be used to import or export 2000 MW for internal needs or to the neighboring system. The diagram shows a few examples of outages that can be impactful to the interfaces being discussed.

Two interfaces are mainly monitored with SOLs and operating plans. Interface A addresses thermal constraints to meet facility ratings associated with the three transformers connecting the 735 kV backbone at Bus A to the 230 kV subsystem at Bus B. Interface B is comprised of three transmission lines feeding a subset of the area (mainly Buses C and D) that is prone to voltage instability. Both interfaces are not expected to be problematic with all equipment in-service. Issues arise when an outage occurs (planned or forced). Mitigating actions are then required, either in operations planning or in real-time, to ensure a secure state of the subsystem should the contingency occur. For such a complex system, planners typically study system conditions with all generation on-line and transmission equipment available. The planner does not study all the conditions that could occur in operations, which inevitably results in constraints for system operators to manage that are not studied in the planning horizon.

The current enforceable standards require TOPs and RCs to operate within SOLs and IROLs, to plan ahead of time for potential exceedances and to have operating plans to address any exceedance. For this example, this is not an issue and all procedures and means are in place to ensure reliability of the 735 kV backbone and limit any risk of outages within the subsystem. However, the question arises if the interfaces shown here warrants establishment of an IROL as proposed by the two frameworks being considered.

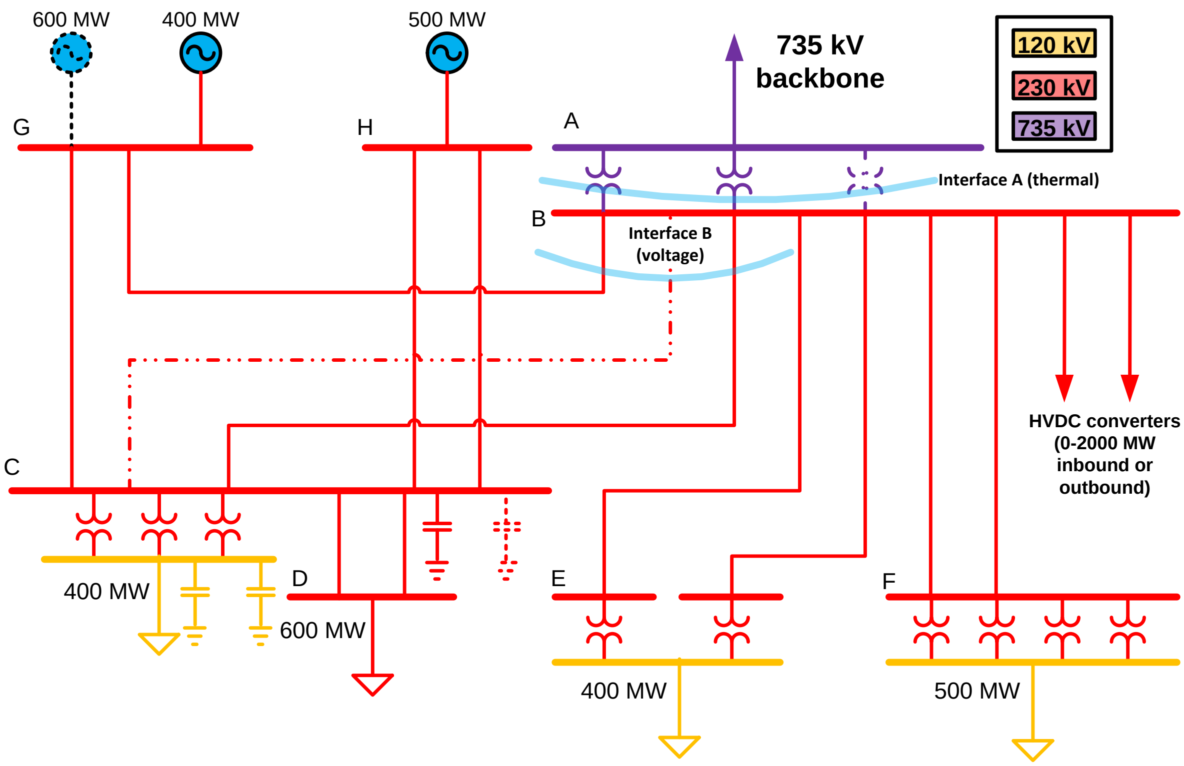

Figure 3.6: Hydro Quebec Example System

Interface A (thermal)

The limits applicable to interface A are studied ahead of real-time and post-contingency analysis is performed though RTCA to ensure that the applicable facility ratings for the transformers are met. For the transmission planner, P1 contingencies (N-1) are not an issue, and P6 (N-1-1) are addressed with the allowable load shedding and system adjustments (that may or may not be aligned with the reality of operating constraints). Therefore, for planned and expected system conditions, transfers will be limited, generation will be committed, or outages will be denied to ensure that the next single contingency will not result in exceeding the SOL linked to that interface (i.e. exceeding the facility ratings of the transformers, the highest being 1500 MW). For example, if an outage needs to be scheduled on one transformer, the impact of the next N-1 contingency will be assessed and operations planning studies will configure the system to operate within the required SOLs. Here is a description of a typical sequence of events managed through operating plans that would otherwise be problematic if forced to establish an IROL:

- Initial condition : 3 transformers in service, 2430 MW transfer (1900 MW of internal load plus internal generation and HVDC export), 3000 MW post-contingency limit (post-contingency emergency rating of 2 remaining transformers)
- Some units at Bus G are unavailable due to planned outages and HVDC transfers are committed
- One transformer trips (forced outage)
- New limit calculated by RTCA: 1500 MW, operating alarm to proceed with system adjustments

- Operating procedures are executed to return within applicable ratings as soon as possible using the available means (aimed at 30 minutes, but not required to shed load to meet the delay).
- If the second contingency shall occur before that (last transformer overloaded beyond its highest Facility Rating), a load shedding plan would be put in place to try and manage the overload before losing the whole subsystem.

Figure 3.7 shows the voltage and frequency at Bus A for the simulation of a contingency of the last transformer, resulting in the complete loss of the subsystem generation and load. The net loss (2430 MW) results in no adverse impact on the remaining BES system (the impact is demonstrated as contained). The overfrequency is within acceptable limits and a generation rejection scheme is used as a safety net to ensure extra margin. In this example, forcing the establishment of an IROL would:

1. Confuse the operators on the level of awareness required relative to the priority of the actions
2. Force pre-contingency load shedding for a very low probability event (loss of 2 transformers within a short timeframe)
3. Put frequent and unnecessary constraints on generation and HVDC dispatch that would cause other reliability issues
4. Delay outage scheduling due to the lack of available system adjustments to meet the 30 minute delay, which would be detrimental to reliability and raise the risk of equipment failure.

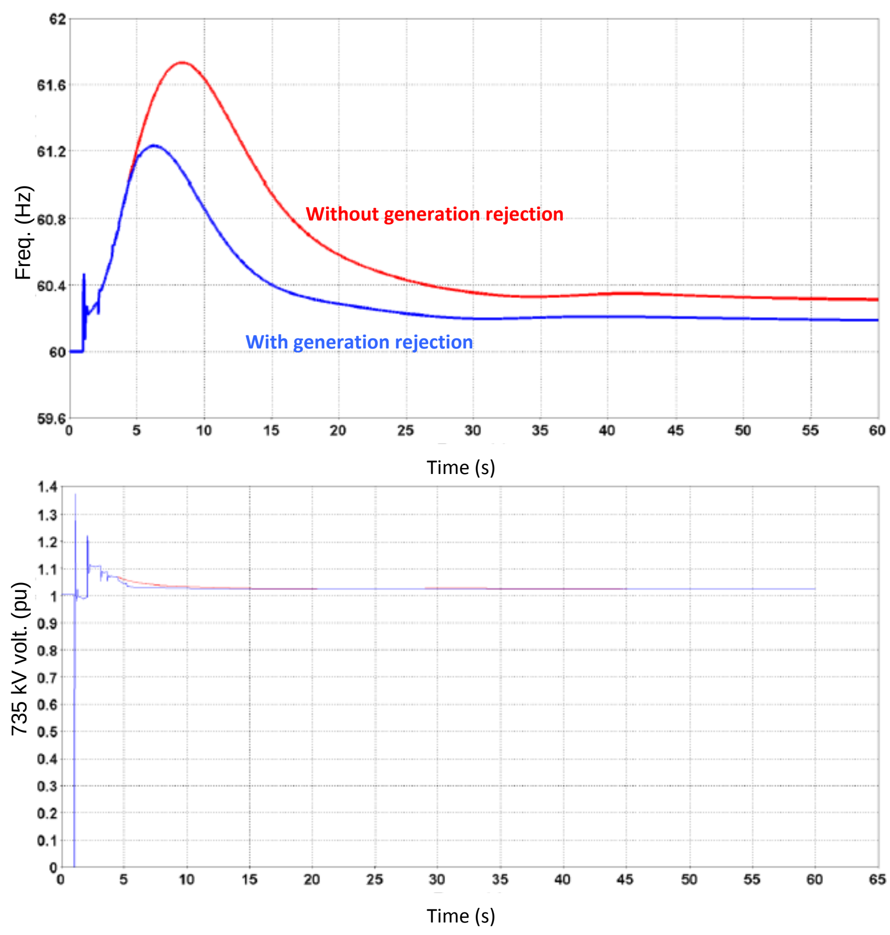

Figure 3.7. Hydro Quebec Stability Example

According to IROL Framework B, any amount of load loss due to cascading warrants the establishment of an IROL. In this example, applying such a concept goes beyond what the system was planned for and is not warranted. On the other hand, Framework A provides the RC with flexibility to consider the cost of load loss, containment and bounding of any potential instability or cascading conditions, as well as the likelihood of occurrence. In this situation, the RC would balance the risks of the potential load loss versus the requirement to shed load pre-contingency in determining whether the cascading would be mitigated with an SOL or an IROL. In either case, the risk would be managed; however, Framework B drives the RC to manage that risk by shedding load pre-contingency.

Interface B (voltage)

Interface B is subject to voltage instability for mainly industrial customers with voltage-sensitive loads. The power transfer through this stability-related SOL depends on the available generating units, the status of the transmission lines, and the connected capacitors (mainly at Bus C). The fast voltage collapse can be easily demonstrated as contained with no impact outside of Buses C and D. Still, outages are carefully scheduled to meet the performance requirements with regards to the next N-1 contingency during real-time. Again, issues arise when an unplanned condition or forced outage occurs in real-time.

One example would be a situation where a transmission line is scheduled for a long duration outage for which a significant delay is required to cancel the maintenance and bring the line back into service. All studies and procedures are then completed to configure the system properly and operate within SOLs. However, if during real-time operations an unexpected issue occurs with one generating unit (e.g., 600 MW at Bus G), this would result in an SOL exceedance (again, with an impact limited to voltage collapse affecting local load if the contingency were to occur). In this situation, procedures would require the availability of capacitors and commitment of other generating units to limit the transfer level on the interface and maximize voltage support.

Similar to many local subsystems, the time required to proceed with those actions greater than 30 minutes. Forcing the establishment of an IROL with compliance obligations, urgency to act, and preventive load shedding does not make sense considering the likelihood of the N-1-1 event and its limited impact on system reliability. For such a case, the preparation of clear operating plans, with realistic steps to mitigate the SOL exceedance within a reasonable timeframe, is aligned with the current standards and industry practices to ensure an adequate level of reliability. Establishing an IROL would require more frequent and unnecessary load shedding of critical industrial customers who would rather tolerate the low risk of complete loss rather than being shed before the contingency actually happened.

Again, Framework B in this case would drive the RC to pre-contingency load shedding to mitigate the local voltage instability that is proved to be contained to a load pocket. Framework A would give the RC flexibility in using a stability-related SOL (rather than an IROL) if the instability was of relatively small impact to the overall BES and proven to be contained via studies.

Illustrative Example 6 – ISO-NE

This example shows two power plants connected to the same 345 kV breaker-and-a-half bus configuration (see Figure 3.8). With all lines in service, there are no restrictions to generation output. However, under outage conditions, there is a risk to unit(s) angular instability requiring the establishment of an SOL (or IROL). Figure 3.8 (right) shows the bus configuration when one breaker (red) is out of service pre-contingency, and another breaker becomes stuck during clearing (yellow). This puts the output of both plants on the 115 kV system, causing instability of both plants. To mitigate this instability, a 150 MW reduction in output is needed. This can be achieved by either (i) ramping one or both units or (ii) tripping a unit. The question becomes whether the SOL should be deemed an IROL, and the implications this can have in real-time operations. Below are some important considerations to this determination:

- **Stability-Based SOL:** As a stability-based SOL, there is no Tv yet operating plans will attempt to mitigate an SOL exceedance within a reasonable amount of time. The consequence of the contingency occurring are the loss of one or more generating units due to angular stability that do not affect other parts of the BPS (i.e., transmission elements other than the directly connecting resources). This instability has been proven to be contained to these two units, adjoining transmission circuits may be lost, but the impacts do not extend beyond there.
- **IROL:** If the SOL was deemed an IROL, there are adverse consequences to new decisions that must be made. All operating actions, up to and including unit tripping, must be completed within the Tv. If unit redispatch down 150 MW was not able to meet the 30 minute Tv, the plant would be tripped to return within this limit within the timer. Plant tripping near full output can have serious adverse impacts on the electric machine and its related components, and should therefore be avoided.

Based on these considerations, the RC has chosen to establish a stability-based SOL with expected mitigating actions within around 45 minutes to eliminate the risk of unit instability. This is a much more prudent operating decision than unnecessary unit tripping.

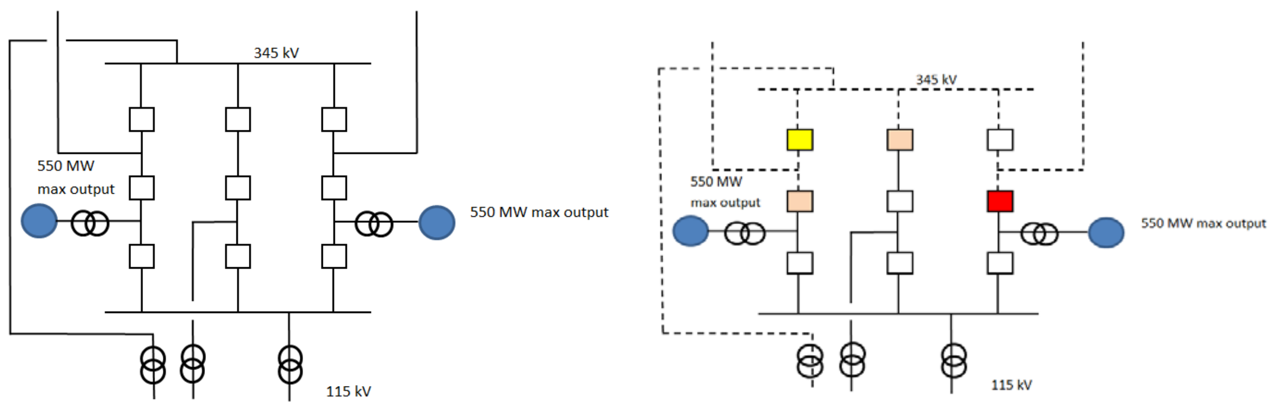

Figure 3.8: 345 kV Bus Configurations

Illustrative Example 7 – Southern Company

The following describe transient stability scenarios that would be classified as SOLs with Framework A proposed initially by the MEITF yet would be classified as IROLs with the alternate Framework B that is believed to be supported by FERC. Note that none of the plant active power output restrictions in these example are large enough to cause any Balancing Authority (BA) resource adequacy or balancing issues.

Scenario 1: Hydro Plant Limit

A hydro plant is connected to the grid via three 230 kV circuits. With all lines in service, the plant is stable at all load levels for any normally cleared 230 kV line fault. For two of the three 230 kV lines, if either of these two lines is out pre-contingency, there is a stability limit which is less than the full MW output of the plant. If the plant MW stability limit is exceeded and the contingency occurs, the resulting instability causes the impedance swing to go through the remaining transmission line which[9]:

1. Causes the plant to be isolated from the transmission system and trips

[9] This phenomena is consistent for the plant MW stability limit all the way up to the plant maximum MW output.

2. The only “load” lost is the hydro plant’s running station service

The question becomes whether this stability limit should be an IROL or a stability-related SOL. If the limit becomes an IROL, then the RC must direct the GOP to reduce plant output to within the stability limit within 30 minutes (the Tv). Note that is the action that will be taken, as the Southeastern RC requires that SOLs be honored within 30 minutes. However, if the limit is a stability-related SOL, then the RC has the option of developing an operating plan to address the instability which could take longer than 30 minutes.

Again the question becomes whether it is necessary or prudent to restrict plant output when it is known and studied that the resulting instability will only affect the plant itself, causing it to trip itself off-line. With the framework believed to be supported by FERC, this would have to be classified as an IROL (for no apparent reliability reason) since the impedance swing enters into a transmission element outside the design zone of protection. However, the resulting outcome does not result in customer load loss nor does the exceedance of the limit coupled with the contingency does not put the interconnection in any type of risk. As such, per the MEITF proposed Framework A, a stability-related SOL would be established rather than an IROL.

Scenario 2: Steam Plant

A steam plant is interconnected to the grid via multiple 230 kV lines. With all lines in service and for the outage of one 230 kV line, the plant is stable at all load levels for any normally cleared 230 kV line fault. If a particular second 230 kV circuit is out of service, a stability limit exists that is less than the full MW output of the plant.

If the new plant MW stability limit is exceeded by less than 90 MW and the worse contingency occurs, the resulting instability does not include an impedance swing that trips any additional transmission elements. If the new plant MW stability limit is exceeded by 90 MW up to maximum output of the plant and the worse contingency occurs, the resulting instability causes the impedance swing to go through two transmission elements but does not cause any load trip or unit isolation.

The plant will be subject to a stability limit(s) if there are two certain lines out of service. The only question is if the limit(s) is a stability-related SOL or an IROL. Again, if Framework B, believed to be supported by FERC were adopted, this unit would have an SOL at one operating point and an IROL beyond that operating point. This is because at some plant active power outputs the impedance swing does not affect transmission elements and at higher outputs it does. However, in either case, the resulting transient instability is proved to have no impact on load loss nor negatively impact reliability of the larger BES.

Currently, consistent with their SOL methodology and in alignment with the MEITF-proposed Framework A, Southern monitors and honors these stability limits during outage conditions using SOLs.

Scenario 3: Hydro Plant Limit

Another hydro plant is connected to the grid via three 230 kV circuits. With all lines in service, the plant is stable at all load levels for any normally cleared 230 kV line fault. For two of the three 230 kV lines, if either of these two transmission lines have a planned or unplanned outage, there is a stability limit that is less than the full MW output of the plant.

If the new plant MW stability limit is exceeded by less than 70 MWs and the worse contingency occurs, the resulting instability does not include an impedance swing that trips any additional transmission Elements. If the new plant MW stability limit is exceeded by 70 MWs up to Pmax of the plant and the worse contingency occurs, the resulting instability causes the impedance swing to go through two transmission elements which causes the plant to be isolated from the BES and trips approximately 20 MW of load. Once again, if Framework B, believed to be supported by FERC were adopted, this unit would have an SOL at one lower operating point, which is the limit that Southern would operate to, and an IROL beyond that operating point.

Similar to the previous examples, establishing an IROL with mandatory action within 30 minutes (fairly tight for redispatching this plant) is not warranted by Southern since the outcome for the instability is nearly the same. The 20 MW of load lost during the instability event can be restored very quickly, in the rare occurrence where the contingency occurs with the line out of service already. The system is planned and operated around this local load service, and consistent with the MEITF-proposed Framework A, the instability is bounded and does not impacts BPS reliability and thus does warrant the establishment of an IROL.

Appendix A: Glossary of Terms and Acronyms

Acronym / Term	Definition
BA	Balancing Authority
BES	Bulk Electric System
BPS	Bulk Power System
FERC	Federal Energy Regulatory Commission
GOP	Generator Operator
HVDC	High Voltage Direct Current
IROL	Interconnection Reliability Operating Limit
IROL Tv	IROL Time Limit
NERC	North American Electric Reliability Corporation
NERC MEITF	NERC Methods for Establishing IROLs Task Force
NERC OC	NERC Operating Committee
NERC PC	NERC Planning Committee
OPA	Operational Planning Assessment
RC	Reliability Coordinator
RTA	Real-Time Assessment
RTCA	Real-Time Contingency Analysis
SDT	Standard Drafting Team
SOL	System Operating Limit
TOP	Transmission Operator

Appendix B: MEITF Team Members

The NERC MEITF members and contributors mentioned below were involved in the technical discussions, brainstorming, or development of this assessment.

Name	Entity	Status
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Wayne Guttormson	SaskPower	Member
Vic Howell	Peak Reliability	Member
Gary Keenan	Northwest Power Pool (NWPP)	Member
Dean LaForest	Independent System Operator-New England (ISO-NE)	Member
Charles-Eric Langlois	Hydro Quebec (HQ)	Member
Durgesh Manjure	Midcontinent Independent System Operator (MISO)	Member
Jonathan Prater	Tennessee Valley Authority (TVA)	Member
Nathan Schweighart	Tennessee Valley Authority (TVA)	Member
Hari Singh	Xcel Energy	Member
David Souder	PJM Interconnection	Member
John Stephens	City Utilities of Springfield, MO	Member
Lee Taylor	Southern Company	Member
Dan Woodfin	Electric Reliability Council of Texas (ERCOT)	Member
Emanuel Bernabeu	PJM Interconnection	Contributor
Xinghao Fang	Independent System Operator-New England (ISO-NE)	Contributor
Hamody Hindi	Bonneville Power Administration (BPA)	Contributor
Grant Marchewca	ReliabilityFirst (RF)	Contributor
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