

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Cost of Risk Reduction Analysis

Phase 1: NERC Project 2015-10 Single Points
of Failure (TPL-001-4) Pilot

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RELIABILITY | ACCOUNTABILITY



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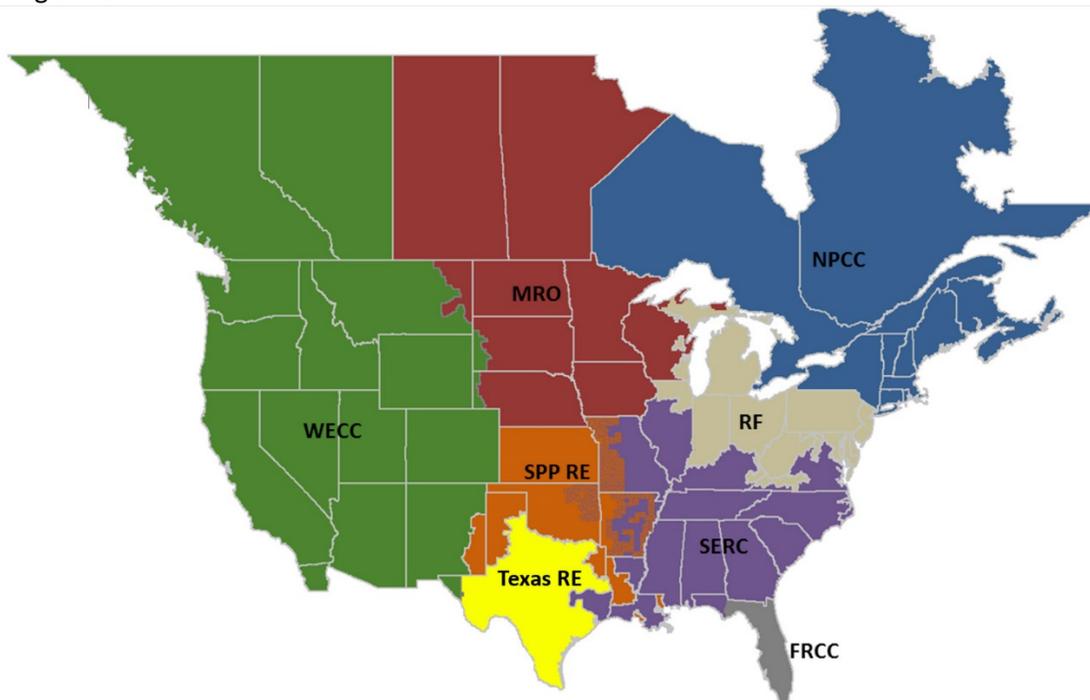
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Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to assure the reliability of the bulk power system (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC’s area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the Electric Reliability Organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC’s jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

The North American BPS is divided into eight Regional Entity (RE) boundaries as shown in the map and corresponding table below.



The North American BPS is divided into eight Regional Entity (RE) boundaries. The highlighted areas denote 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
SPP RE	Southwest Power Pool Regional Entity
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Executive Summary

The North American Electric Reliability Corporation (NERC), Federal Energy Regulatory Commission (FERC), and industry stakeholders have expressed interest in the concept of the Electric Reliability Organization (ERO) performing a cost effectiveness analysis during the standards development process. In response, the NERC Standards Committee (SC) initiated a project to develop a continent-wide process, building on the NPCC Cost Effectiveness Analysis Procedure (CEAP).¹ In October 2012, the NERC SC approved the NERC CEAP² document for a “pilot” along with an Implementation Whitepaper.³ This initial pilot was completed and found by stakeholders to be burdensome to provide the necessary details requested. In response, NERC and the SC are developing a conceptual process named Cost of Risk Reduction Analysis (CRRRA). The purpose of the CRRRA is to gauge risk, the potential for occurrence of that risk, consequences of not addressing the risk, identify potential egregious costs, and determine the relative effectiveness and cost of alternative approaches to meet the reliability standard’s objective. The ERO Cost Effectiveness Team (CET), consisting of an independent group of industry participants, Regional Entity staff, and lead by a member of the Standards Committee and NERC Staff, conducted Phase 1 of the draft CRRRA process, as a pilot, using Project 2015-10 Single Points of Failure (TPL-001-4).

The CRRRA process incorporates input received from the NERC Member Representatives Committee (MRC), ERO management, and the NERC SC. The draft CRRRA process consists of two phases. Phase 1 focuses on the likelihood of a defined risk to the Bulk Electric System (BES) occurring, determining potential stakeholder costs that are associated with addressing the risk, potential reliability consequences of not addressing the risk, and developing potential cost effective solutions and alternatives to mitigate the risk. This first phase should be conducted prior to standards development activities or during the standards authorization request (SAR) stage and could potentially be conducted during consensus building activities or by the Reliability Issues Steering Committee (RISC) if a new risk to the BES emerges. Phase 2 would be performed once a NERC standard drafting team (SDT) has developed a solidified set of draft requirements that meet the reliability objective of the standard. At that time more detailed cost data can be compiled and reported on as well as soliciting alternate cost effective approaches from stakeholders.

The CET appreciates the effort put forth by all commenters who submitted responses to the Phase 1 pilot for Project 2015-10 Single Points of Failure. The CET conducted a 30-day public comment period to solicit estimated risk, cost, and related information from the industry. The comment period began on April 27, 2016 and closed on May 26, 2016. Stakeholders were asked to provide feedback electronically through the NERC Standards Ballot System (SBS). There were 47 sets of responses, including comments from approximately 132 commenters and approximately 50 companies representing nine of the industry segments.

It is important to preface evaluation of stakeholder comments analysis with a note that this project was initiated based on a comprehensive assessment by the System Protection and Control Subcommittee (SPCS) and the System Analysis and Modeling Subcommittee (SAMS) of the study of protection system single points of failure in response to FERC Order No. 754. The assessment confirmed the existence of a reliability risk associated with single points of failure in protection systems that warrants further action. In addition to the assessment, FERC issued two directives in Order 786⁴. Irrespective of industry opinion regarding risk or cost, NERC is required to address the reliability issue that FERC identified in its directives. In this instance and in response to the FERC Order, NERC engaged the SPCS and SAMS to review the directives and determine how best to address them. Based on this

¹ https://www.npcc.org/Standards/Regional%20Standards%20General/NPCC_CEAP_2011--LP10-12-11_11-4-11.pdf

² http://www.nerc.com/pa/Stand/Cost%20Effective%20Analysis%20Process%20CEAP%20for%20NERC%20ERO/NERC_CEAP_Guideline_10-1-2012.pdf

³ http://www.nerc.com/pa/Stand/Cost%20Effective%20Analysis%20Process%20CEAP%20for%20NERC%20ERO/Implementation_of_CEAP-10-1-2012.pdf

⁴ <http://www.nerc.com/FilingsOrders/us/FERCOrdersRules/E-2%20Transmission%20Planning%20Rel.%20Strd.pdf>

analysis and comments received in response to the Phase 1 pilot, the SAR may be revised to address these outstanding directives.

The majority of the commenters believe the proposed revisions to TPL-001-4, as outlined in the SAR, pose minimal reliability benefits and note that there is currently a low risk to the BES for the issues identified in the FERC directives. The CET was encouraged by the amount of implementation cost data submitted by stakeholders and the potential benefits identified by stakeholders.

Response to Comments

Standard Type – TPL – Transmission Planning

Revision of TPL-001-4 Transmission System Planning and Performance Requirements

In response to FERC Order No. 754, The NERC System Protection and Control Subcommittee (SPCS) and System Analysis and Modeling Subcommittee (SAMS) developed a report and a set of recommendations to address potential reliability concerns entitled “Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request.”⁵ The recommended modifications address specifics of Protection System component failure, aspects of steady state and stability performance testing, and expansion of extreme event assessment requirements in order to minimize the potential risk of Single Points of Failure. The Phase 1 pilot posed questions related to the two FERC directives not discussed in the joint SPCS/SAMS report. If it is determined that those directives should not be addressed by Project 2015-10 Single Points of Failure Standard Drafting Team (SDT), the SAR may need further modification to address this change in project scope.

Functional Model Version 5 Entity Applicability

Stakeholders who are applicable to this CRRA are Planning Coordinators and Transmission Planners.

CRRA Phase 1 Analysis

The following two survey questions, with three additional sub parts each, were posed to the industry:

1. Reliability Standard TPL-001-4 requires an entity to consider planned maintenance outages greater than six months in duration in its studies. What, if any, risk is there to the reliable operation of the bulk power system (BPS), as defined in Section 215 of the Federal Power Act (i.e., “operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance . . . or unanticipated failure of system elements”) if planned maintenance outages of less than six months in duration are not considered in studies during one or both seasonal off-peak periods? Please explain your response:
 - a. If there are risks to the reliable operation of the BPS, are the likelihood of the occurrence of these risks low, medium or high? Please explain your response:
 - b. What costs should be considered when evaluating these risks or in adding planned outages less than six months to TPL-001-4? Please explain your response:
 - c. If you identified one or more risks and identified a likelihood of “medium” or “high”, is there a more cost effective manner to reduce them rather than revising TPL-001-4 or is there a preferred approach to revising TPL-001-4 that takes into consideration cost effectiveness? Please explain your response including descriptions of potential cost effective solutions and the associated benefits to reliability:
2. What, if any, risk to the reliable operation of the BPS, as defined under Section 215 (see question 1 above) is there if an entity does not perform stability analyses for the P0, P1 and P2 categories in TPL-001-4 that consider the possible unavailability of long lead-time equipment? Please explain your response:
 - a. If there are risks to the reliable operation of the BPS, are the likelihood of the occurrence of risks low, medium or high? Please explain your response:
 - b. What costs should be considered when evaluating these risks? Please explain your response:

⁵ [http://www.nerc.com/comm/PC/System Protection and Control Subcommittee SPCS 20/2015-10 FERC Order 754 Final Report - SPCS-SAMS.pdf](http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%20/2015-10%20FERC%20Order%20754%20Final%20Report%20-%20SPCS-SAMS.pdf)

- c. If you identified one or more risks and identified a likelihood of “medium” or “high” is there a cost effective manner to reduce them rather than revising TPL-001-4 or is there a preferred approach to revising TPL-001-4 that takes into consideration cost effectiveness? Please explain your response including descriptions of potential cost effective solutions and the associated benefits to reliability:

Data Analysis and Conclusions:

A more detailed summary of the comments received from the industry CRRRA pilot of the Phase 1 survey may be found in the Appendix:

In reference to Question 1 and its subparts:

Some respondents were of the opinion that the inclusion of planned maintenance outages of less than six months in duration in planning studies would not address a reliability risk. Many expressed the opinion that these are shorter duration outages which occur in the operations planning horizon and are already addressed in other reliability standards, notably IRO-017-1. Some commenters indicated this would be a duplicative effort and the effects of these outages need not be studied and considered in planning studies since operations planning address these risks in real time and seasonal analysis. Also, the majority of respondents indicated there was a low likelihood of this risk occurring and posing a reliability issue to the BES. Some believed this concern is a very low risk and is redundant in Requirement R5 of TOP-002-2.1b.

Additionally, costs were identified by commenters in relation to extra planning studies, personnel to run and evaluate the studies, and potential computing time and equipment.

In reference to Question 2 and its subparts:

Regarding the risk posed by not considering a stability analysis for the P0, P1 and P2 contingencies and the availability of long lead-time equipment, the majority of the industry commenters identified this as no/minimal risk. Commenters noted that operators have the ability to operate around problems in their analysis and also that it was sufficient that P3-P7 already include the study of all loss of long lead-time equipment scenarios. The majority of industry commenters indicated that the likelihood of occurrence of the risk affecting the reliability of the BES was low. Also noted was that in consideration of the scope of contingency events already considered, it would be unlikely that critical events would be missed. Events which would tend to produce the more severe impacts on system stability are already given considerable attention.

Commenters expressed concern regarding the costs associated with stability analysis of long lead-time equipment. Further, the additional study time and spare equipment inventory for reactive devices would likely have a low probability of failure. Therefore, both of these could be an unnecessary cost burden.

Those industry commenters who identified the risk as a potential medium or high impact reliability concern had suggestions to address the concerns in line with the recommendations of the SPCS and SAMS report, as identified in the posted SAR.

Observations and Conclusions

The Observations developed by the CET are as follows:

- The two CRRRA questions for this project focused on identification of costs and risk mitigation associated with two reliability directives issued by FERC in Order 786. As such, NERC must consider and address these directives.
- The directive to consider planned outages of less than six months duration in planning studies seems to be of minimal value, as this is already performed in operations planning pursuant to TOP-002-2.1b.

- A significant amount of additional study work would be necessary to consider the planned (but not Reliability Coordinator approved) short duration (less than six months) outages in the long-term planning horizon, and is likely to require additional human resources, studies and computer time, and equipment.
- Additional consideration of stability analysis for the P0, P1 and P2 contingencies for long lead-time items could be a concern, as some entities identified it as a risk while others believed it would be considered in the planning studies currently conducted.
- Long lead-time items and increasing a spare equipment inventory for reactive devices may not prove to be cost effective in addressing issues identified by a more rigorous stability analysis for additional planning contingency categories.
- No egregious costs were identified by entities for the proposed directives and the risk identified to the BES appears to be minimal based on the responses.

The CET recommends that additional conversation occur with FERC staff to discuss the concern of considering maintenance outages of less than six months duration in planning studies, as this appears to be addressed in the operations planning horizon in TOP-002-1b. Introducing this analysis into the TPL-001-4 could potentially create redundancy with little or no benefit to reliability.

The CET recommends that any further revisions to the standard that were suggested in comments that are outside the scope of the SAR be held in abeyance until such time as the standard is under an Enhanced Periodic Review. The CET also recommends that, once the SDT has solidified a set of requirements, a cost effective analysis should be conducted which evaluates alternatives to each of the draft requirements (Phase 2).

The CET Team respectfully submits this report for informational purposes to the SC, SDT, and stakeholders to better inform them of potential risks, costs, benefits, and impact as Project 2015-10 “Single Point of Failure (TPL-001-4)” develops potential solutions.

CET Team Participants

The below listed individuals were active participants in the development of the report and opinions contained herein. In addition, there were other members of NERC Staff and Legal who assisted with administrative tasks, posting and other supporting activities.

- Michelle D’Antuono – Occidental
- Howard Gugel - NERC
- Peter Heidrich – FRCC
- Steve Rueckert – WECC
- Phil B. Winston – Southern Company
- Guy V. Zito – NPCC

Appendix: Summary Consideration of Comments

Summary Consideration of Comments

“Pilot” of the NERC CRRRA Phase 2 Regarding Project 2015-10 Disturbance Monitoring and Reporting Requirements

The full set of industry comments may be found at:

http://www.nerc.com/pa/Stand/CostEffectivenessPilotProgram/CEP_RAW_Comments_Word_052716.pdf

Question 1:

Reliability Standard TPL-001-4 requires an entity to consider planned maintenance outages greater than six months in duration in its studies. What, if any, risk is there to the reliable operation of the Bulk Power System (BPS), as defined in Section 215 of the Federal Power Act (i.e., “operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance . . . or unanticipated failure of system elements”) if planned maintenance outages of less than six months in duration are not considered in studies during one or both seasonal off-peak periods? Please explain your response:

- No risk. Unconfirmed outages are not included in planning studies. Planned maintenance outages are only included in operational studies. With the various categories of contingencies which need to be considered already in TPL-001-4 (both single and multiple element contingencies) to further give consideration to outages of less than six months duration would appear to be needlessly redundant. (15 respondents)
- No risk. Planned maintenance outages are only scheduled during off-peak conditions. Transmission planning evaluations consistently have demonstrated no negative impact to the immediate and neighboring bulk power system. (2 respondents)
- Low/Minimal risk. There are specific scenarios involving planned maintenance outages that could pose a risk to the BPS and warrant special attention. The PC and TP should have the leeway to determine which scenarios should be included in their assessments and NERC should not structure standard Requirements that mandate a specific minimum number, nor that require “all” such scenarios. (1 respondent)
- Low/Minimal risk. Impractical to consider in planning horizon, since operations planning address these risks in real time and seasonal analysis. (14 respondents)
- Moderate risk. Potential delay in projects and maintenance. Modeling outages would allow Transmission Planner to respond to RC rejection of outage. (2 respondents)
- Alternate proposal - Existing wording in the NERC standard be identified or clarified to include outages of more than six-months should include a sensitivity analysis if the outage occurs in the spring and/or fall months. (3 respondents)
- Alternate proposal – The standard should be revised to remove the six month planned outage requirement and instead reinstate the provisions in the previous TPL standard where off-peak planning cases are analyzed to ensure the system is capable of supporting a planned outage for each element of the system while simultaneously being secure for the next contingency. (2 respondents)
- Alternate proposal – NERC might consider expanding the application of IRO-017-1 to outages planned outside of Operations Planning Horizon. (2 respondents)

Note: Addressing reliability risks associated with planned maintenance will be cost-effective through an Outage Coordination program, such as the one administered by ISO-NE (and as contemplated by IRO-017-1). This approach also avoids disruption to the long-term system planning assessment under TPL-001-4 for several reasons, including:

- The iterative process of scheduling and approving outages requires a high degree of communication and coordination up to and including Real-time. Operations personnel have developed the experience, tools, procedures, and process needed to manage and minimize reliability and economic impacts associated with planned outages. IRO-017-1 requires the development of a process, communication, and resolution of identified conflicts.
- In contrast, studies under TPL-001-4 are typically done by system engineers doing relatively static studies on a relatively known system, and publishing a needs assessment. Requiring such an assessment under TPL-001-4 would simply be an additional step to what outage coordinators need to do anyway.

Question 1a: If there are risks to the reliable operation of the BPS, are the likelihood of the occurrence of these risks low, medium or high? Please explain your response:

- Low (34) – Already covered in outage coordination (IRO-017-1). Best covered in Operations studies. Already captured in N-1-1 analysis in TPL-001-4. Also covered in R5 of TOP-002-2.1b. Operations planning studies are performed prior to approval of the planned outage. If there exists a risk to the BPS, then the planned outage is canceled or postponed until the outage can be taken at a time when there is no risk to the BPS. If the standard drafting team develops any requirements for evaluation of short-term planned maintenance outage those requirements should provide options that limit the evaluations to “critical” facilities such as transfer paths. The transmission planner should not be obligated to study every planned maintenance; an approach that would create an administration burden without justifiable reliability benefit.
- Medium (3) – The likelihood of a planned (scheduled or future to-be-scheduled) outages is 100% (high). And the likelihood of an unplanned planning event contingency occurring during planned outage conditions may be low. So, the overall likelihood of the some planned outages and unplanned contingencies combinations is probably medium. The BPS may not operate reliably for certain planned maintenance outages if the system is not planned to accommodate such outages, or restrict the RC outage coordination processes in approving certain planned outages.

Question 1b: What costs should be considered when evaluating these risks or in adding planned maintenance outages less than six months to TPL-001-4? Please explain your response:

- This would likely require an additional engineer for every entity required to comply with the TPL standards.
- If there are multiple planned outages in the same year, multiple scenarios will need to be studied to get an accurate analysis, dramatically increasing the amount of study work. Again, most of this analysis is already performed in the operating horizon, leading to further duplication of work.
- As outages are added, removed or moved, studies may need to be re-run for the assessment. A system or additional process would need to be added to track changes to the outage schedule.
- Delayed projects and/or maintenance cost may result if outage requests to perform work are rejected.
- Licensing costs of modeling tools may also increase if additional FTEs are added.
- Additional costs to consider include duplicative staff, duplicative equipment, additional computing time, and compliance enforcement costs related to performing additional annual planning assessments for

TPL-001-4 which are already adequately and properly covered in seasonal, next-day, and current day studies.

- Potential capital funding required for corrective action plans to address issues that historically could have been mitigated through operational techniques.
- Working around a maintenance coordination issue on a system not designed to handle the maintenance can increase the risk to reliability by having to rely on operating guides and workarounds. Increased costs also may occur due to required re-dispatch and/or shifting the maintenance to higher dispatch cost periods. Also, uncertainty of when maintenance can be scheduled and/or denial of scheduled maintenance can increase cost to asset owners that rely on contract personnel.
- The cost of potential corrective action plans that would reduce or eliminate the risk of a large amount of firm load loss or firm transmission service interruption should be considered.
- The cost, either direct or unintended, of developing, documenting, and auditing an assessment with an administrative focus on achieving compliance with a standard rather than on analyzing and mitigating risks to BPS reliability.

Question 1c: If you identified one or more risks and identified a likelihood of “medium” or “high”, is there a more cost effective manner to reduce them rather than revising TPL-001-4 or is there a preferred approach to revising TPL-001-4 that takes into consideration cost effectiveness? Please explain your response including descriptions of potential cost effective solutions and the associated benefits to reliability:

- Regardless of the potential risk level, the cost-effective alternative is to accept the daily system studies which are already completed under TOP-002 Standards and are currently designed to identify potential risk to the BPS.
- Revise TPL-001-4 to include coordination between transmission planners and operational planners to review the operational studies or to incorporate only significant planned maintenance outages into TPL-001-4 studies, similar to R3.4.1 and R4.4.1.
- The obligation to evaluate planned outages for conditions when they would typically be taken should be part of the requirements for the assessment of “no load loss allowed” planning event contingencies. Otherwise, it should be added to the assessment of extreme event contingencies to evaluate planned outages that are expected to produce more severe system impacts and learn the possible extent of those impacts.
- If the TPL-001-4 standard were modified simply by a rule change for processing P6 contingencies during off-peak cases (Load shed would not be allowed as a mitigation measure), simulation of a facility being removed for maintenance and the resulting system satisfying the “n-1” reliability criteria could be assessed for any time in the Planning Horizon.
- Known planned outages less than six months should be evaluated by Operating personnel in the operating horizon.
- An alternative is to revise the definition of Operational Planning Analysis to change the next day operations part to next day to up to one year.
- If the RC requires the TO/GO to provide rolling 12 months (or longer) outage plans, the RC can evaluate the outages, identify issues, and coordinate the outages in order to avoid scheduling conflicts.

Question 2: What, if any, risk to the reliable operation of the BPS, as defined under Section 215 (see question 1 above) is there if an entity does not perform stability analyses for the P0, P1 and P2 categories in TPL-001-4 that consider the possible unavailability of long lead-time equipment? Please explain your response:

- No risk – The stability analysis for P3 –P7 categories should already include the study of all loss of long lead-time equipment scenarios. (10 respondents)
- No risk – If there is an outage of long lead-time equipment, system operations will operate around any problem that might be indicated by their analysis. From a stability standpoint this would most likely be a small limitation on the amount of generation at a plant near the outage element. (2 respondents)
- Minimal risk – Region already requires the study of unavailability of an autotransformer along with a P0, P1 and P7 event. This would only require an additional study of an autotransformer unavailable with a P2 event. (1 respondent)
- Minimal risk – Operational assessments are already performed and cover these conditions and identify potential risk to the BPS. (1 respondent)
- Low risk – The concerns of instability, uncontrolled separation, and cascading failures of these Facilities are likely caused by an exceedance of an Interconnected Reliability Operating Limits, and usually under conditions representative of a P2 category study. Hence, a risk to the reliable operation of the BPS could exist, and entities should conduct stability analyses regarding these Facilities when they are associated with Interconnected Reliability Operating Limits. (2 respondents)
- Low risk – Studies are already done as part of the spare equipment strategy. A stock of spare long lead-time equipment is maintained to keep a reliable transmission system as well as a stock of parts for repairs. (3 respondents)
- Low risk – The unavailability of long lead-time equipment can only lead to dynamic BES system angular or voltage instability when the equipment is in a crucial location near an area of weak angular or voltage stability. (1 respondent)
- Low risk – If the unavailability of long lead-time equipment is not considered in stability analysis for P0, P1 and P2 events, there is a risk of detrimental impacts to BPS reliability. Generally, the unavailability of long lead-time equipment studied under P0 will be bounded by the existing P1 studies. The unavailability of long lead-time equipment studied under P1 and P2 may not be considered completely bounded by any existing studies. However, given the scope of contingency events already considered, it would be unlikely that critical events would be missed. (1 respondent)
- Low risk – There are certain scenarios involving the unavailability of major long lead-time Transmission equipment that could pose a risk to the BPS and warrant special attention to System stability. However, the instance of such events that cause angular or voltage stability impacts beyond those observed by traditional steady state studies is much more infrequent, and adding events to Stability analysis without proper engineering judgment can add extremely significant wasted time. The PC and TP should have the leeway to determine which scenarios should be included in their assessments, based on events that are expected to produce more severe System impacts. (1)
- Medium risk – If an entity does not perform stability analyses, IROLs may not be identified. Additional impacts including SOL exceedances, voltage stability, dynamic stability, and transfer capability may not be realized without proper study parameters. (3 respondents)
- Medium risk – There are concerns that a P2 stability analysis with an assumed third contingency base case long-term outage can easily go beyond typical electric grid designs resulting in additional transmission construction. The risks posed by not performing P0, P1, and P2 stability analyses is specific in nature depending upon the type of equipment and the impact of that equipment. (3 respondents)
- Medium risk – There might be performance issues that remain uncovered unless a stability assessment is performed on time, in particular if such assessment calls for significant de-rates or implementation of a RAS. (3 respondents)

- Medium risk – Stability analysis is already required for various N-1 and N-1-1 contingencies that include loss of the equipment. The inclusion of stability analysis on contingency combinations with a significantly lower probability of occurrence could potentially identify new exposures. (1 respondent)

Question 2a: If there are risks to the reliable operation of the BPS, are the likelihood of the occurrence of these risks low, medium or high? Please explain your response:

- Low (23 respondents) – There is a chance that if a long lead-time piece of equipment is out of service, that there is a stability risk to the system that is unknown. The unavailability of long lead-time equipment with the potential to cause impacts to the BPS are low probability, infrequent events. Given the scope of contingency events already considered, it would be unlikely that critical events would be missed. Events which would tend to produce the more severe impacts on system stability are already given considerable attention. Contingency events which would tend to have the more severe impacts on transient stability issues, typically related to generation outlet facilities, are already given significant attention in analysis work related to TPL-001-4. Long lead-time equipment tends to be transformers. If a BES transformer is out of service, the next worst outage is typically loss of another parallel transformer. This contingency is already considered as a P6 event.
- Medium (5 respondents) – Medium, because the issue is important, but would most likely be looked at for stability by most utilities if thermal or Low voltage issues in outage studies showed reason for concern. Low to Medium risk of occurrence, depending on the equipment being evaluated.
- High (2 respondents) – Although preventive measures, such as shared transformer inventories, have been implemented to address the availability concern of high-voltage substation transformers, these measure may not account for every possible catastrophe.
- Low to high (1 respondent) – The issue is each case may present a different level of risk to the BPS. Without studying it, the risk is unknown until the operations horizon.

Question 2b: What costs should be considered when evaluating these risks? Please explain your response:

- Additional engineering resource would be required.
- The cost of duplicative study work.
- Costs can range from the need for additional studies or a corrective action plan (low costs) to the need to purchase additional spare equipment (signification costs).
- Licensing costs of modeling tools may also increase if additional FTEs are added.
- Additional costs that should be considered include potential capital funding required for corrective action plans as a result of the new requirement.
- Spare inventory for reactive devices with a low probability of failure would create a significant cost burden on utility ratepayers nationwide. Many of these reactive support devices are custom designed and a complete spare would have a high cost for a minimal system reliability benefit.
- Opportunity costs associated with shifting existing staff away from other reliability studies.

Question 2c: If you identified one or more risks and identified a likelihood of “medium” or “high” is there a cost effective manner to reduce them rather than revising TPL-001-4 or is there a preferred approach to revising TPL-001-4 that takes into consideration cost effectiveness? Please explain your response including descriptions of potential cost effective solutions and the associated benefits to reliability:

- Revising the TPL-001-4 standard to evaluate P2 stability impacts of long lead-time equipment associated with identified IROLs seems reasonable.
- Use existing operations outage studies performed for TOP standards to point to the need or create a mechanism for which the outages would be studied for stability on an “as needed” basis.
- Use of historical outage probabilities in development of the standard to remove the requirement for evaluating the unavailability of long-lead equipment for lower probability failures, including series and shunt capacitors, series and shunt reactors, and dynamic reactive support devices.

A cost effective manner to address the potential risk could be to include stability analyses for the P0, P1 and P2 events when evaluating the conditions that the system is expected to experience during the possible unavailability of the long lead-time equipment.