Comment Report

Project Name: 2015-10 Single Points of Failure SAR

Comment Period Start Date: 5/26/2016

Comment Period End Date: 6/24/2016

Associated Ballots:

There were 31 sets of responses, including comments from approximately 31 different people from approximately 31 companies representing 8 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with the proposed changes to the SAR? If no, please provide comments.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
ACES Power Marketing	Colleen Campbell	6	NA - Not Applicable	ACES Standards Collaborators	Ginger Mercier	Prairie Power, Inc.	1,3	SERC
					Shari Heino	Brazos Electric Power Cooperative, Inc.	1,5	Texas RE
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Chip Koloini	Golden Spread Electric Cooperative, Inc.	5	SPP RE
					Mark Ringhausen	Old Dominion Electric Cooperative	3,4	RF
					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
					Liam Stringham	Sunflower Electric Power Corporation	1	SPP RE
SERC Reliability Corporation	David Greene	10	SERC	SERC PSS	Shih-Min Hsu	Southern Company Services – Transmission	1	SERC
					John Sullivan	Ameren	1	SERC
					Phil Kleckley	SCE&G	1	SERC
					David Greene	SERC	10	SERC
Electric Reliability Council of Texas, Inc.	Elizabeth Axson	2		IRC Standards Review Committee	Elizabeth Axson	ERCOT	2	Texas RE
					Charles Yeung	SPP	2	SPP RE
					Ben Li	IESO	2	NPCC
					Mark Holman	PJM	2	RF

					Matt Goldberg	ISO-NE	2	NPCC
					Greg Campoli	NYISO	2	NPCC
MRO	Emily Rousseau	1,2,3,4,5,6	MRO	MRO-NERC Standards Review Forum (NSRF)	Joe Depoorter	Madison Gas & Electric	3,4,5,6	MRO
					Chuck Lawrence	American Transmission Company	1	MRO
					Chuck Wicklund	Otter Tail Power Company	1,3,5	MRO
					Dave Rudolph	Basin Electric Power Cooperative	1,3,5,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Jodi Jenson	Western Area Power Administration	1,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Mahmood Safi	Omaha Public Utility District	1,3,5,6	MRO
					Shannon Weaver	Midwest ISO Inc.	2	MRO
					Mike Brytowski	Great River Energy	1,3,5,6	MRO
					Brad Perrett	Minnesota Power	1,5	MRO
					Scott Nickels	Rochester Public Utilities	4	MRO
					Terry Harbour	MidAmerican Energy Company	1,3,5,6	MRO
					Tom Breene	Wisconsin Public Service Corporation	3,4,5,6	MRO
					Tony Eddleman	Nebraska Public Power District	1,3,5	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
Seattle City Light	Ginette Lacasse	1,3,4,5,6	WECC		Pawel Krupa	Seattle City Light	1	WECC

				Seattle City Light Ballot Body	Dana Wheelock	Seattle City Light	3	WECC
					Hao Li	Seattle City Light	4	WECC
					Bud (Charles) Freeman	Seattle City Light	6	WECC
					Mike haynes	Seattle City Light	5	WECC
					Michael Watkins	Seattle City Light	1,3,4	WECC
					Faz Kasraie	Seattle City Light	5	WECC
					John Clark	Seattle City Light	6	WECC
Southern Company - Southern Company Services, Inc.	Katherine Prewitt	1		Southern Company	Scott Moore	Alabama Power Company	3	SERC
					Bill Shultz	Southern Company Generation	5	SERC
					Jennifer Sykes	Southern Company Generation and Energy Marketing	6	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7	NPCC	RSC no ISO-NE, IESO	Paul Malozewski	Hydro One.	1	NPCC
					Guy Zito	Northeast Power Coordinating Council	NA - Not Applicable	NPCC
					Rob Vance	New Brunswick Power	1	NPCC
					Mark J. Kenny	Eversource Energy	1	NPCC
					Gregory A. Campoli	NY-ISO	2	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					David Ramkalawan	Ontario Power Generation	4	NPCC

					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Bruce Metruck	New York Power Authority	6	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	UI	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Sylvain Clermont	Hydro Quebec	1	NPCC
					Si Truc Phan	Hydro Quebec	2	NPCC
					Brian Shanahan	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC
					Michael Forte	Con-Edison	1	NPCC
					Kelly Silver	Con-Edison	3	NPCC
					Peter Yost	Con-Edison	4	NPCC
					Sean Bodkin	Dominion	4	NPCC
					Silvia Parada Mitchell	NextEra Energy	4	NPCC
					Brian O'Boyle	Con-Edison	5	NPCC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					Jason Smith	Southwest Power Pool Inc	2	SPP RE
					Kim VanBrimer	Southwest Power Pool Inc	2	SPP RE
					Derek Brown	Westar Energy	1,3,5,6	SPP RE
					Charles Hendrix	Southwest Power Pool Inc	2	SPP RE

					john Allen	City Utilities of Springfield	1,4	SPP RE	
					jonathan Hayes	Southwest Power Pool Inc	2	SPP RE	
					Don Hargrove	Oklahoma Gas and Electric Co.	1,3,5,6	SPP RE	
					Jim Nail	Independence Power and light	3,5	SPP RE	
					Mike Kidwell	Empire District Electric Company	1,3,5	SPP RE	
					Robert Gray	Board of Public Utilities (BPU)	NA - Not Applicable	NA - Not Applicable	
					TARA Lightner	Sunflower	1	SPP RE	

1. Do you agree with the proposed changes to the SAR? If no, please provide comments.

Michelle Amarantos - 1,3,5,6	
Answer	No
Document Name	
Comment	

AZPS believes this creates little risk in the planning horizon. Any potential issues are best identified through next-day, real time and seasonal analysis studies (in conjunction with applicable RCs) to addresses these short duration issues, rather than through TPL-001-4. These planned maintenance outages tend to be rescheduled, as needed, in the operations horizon to account for present conditions. Including these shorter duration planned outages in the Planning Horizon would create the need for 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 studies performed in the operations horizon.

Likes 0	
Dislikes 0	
Response	

Amy Casuscelli - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	

As explained in detail below, Xcel Energy agrees with addressing item 1 (single points of failure) and item 3 (update the reference to MOD standards in R1) with the scope of the SAT, but disagree with item 2 (FERC directives) included in its entirety within the scope. The following comments are in reference to the items listed in the Industry Need and Purpose/Goals sections of the SAR.

Item 1: Agree with replacing "address" by "consider" in the Purpose/Goals section, but find that corresponding changes in the Industry Need section are missing. Specifically, the lead-in sentence in the Industry Need section, "*Modifications have been identified to TPL-001-4*..." implies that the SAMS/SPCS recommendations for modifying TPL-001-4 described within Item 1 are the specific changes to be implemented in TPL-001-4 . It appears that recommendations will be addressed instead of being considered.

Item 2: Agree that SAR scope may include addressing the FERC directives from Order 786. However, the scope should be limited to included "true" FERC directives, which we contend is only contained in Paragraph 40 and not in Paragraph 89. We observe the following clear distinction in the language used by FERC in Paragraph 40 versus Paragraph 89. While Paragraph 40 is certainly a directive ("directs NERC to modify Reliability Standard TPL-001-4") to address the identified (BES reliability) concern and have has the expectation that the concern would be addressed at the earliest opportunity to modify TPL-001-4, we note that Paragraph 89 does not convey a FERC directive to address the stated issue. In fact, Paragraph 89 unambiguously states "*the Commission will not direct a change and instead directs NERC to consider a similar spare equipment strategy for stability analysis upon the next review cycle of Reliability Standard TPL-001-4.*" Consequently, we disagree with including Paragraph 89 within the scope of the SAR. In fact, if addressing Paragraph 89 is not deferred to the next review cycle of TPL-001-4, we see this as contradictory and inconsistent with the SAR-DT's position to defer addressing the TPL-001-4 issues and ambiguities (as identified by Xcel Energy and several other entities in comments submitted for the previous SAR posting) until the next regular review cycle of TPL-001-4. Due to the reasons cited above, we strongly recommend that addressing Paragraph 89 be excluded from the scope of this project.

Item 3: Agree with revising R1 to update reference to soon to be outdated MOD standards.

Additional editorial changes recommended below:

Industry Need Section: Another reason the lead in sentence in the Industry Need section must be revised is that addressing the Paragraph 40 directive comprehensively may require making modifications to additional standards besides TPL-001-4. For instance, modifications may be needed to the IRO-017-1, Outage Coordination, standard whose purpose and applicability has significant overlap with the reliability concern noted in Paragraph 40.

Identify the Objectives Section: Please ensure that a consistent numbering format is used for all three items. Also, please fix the spelling error typos (condiseration, citd, etc)

Detailed Description Section: Shouldn't all three items be described in this section as well? It appears that only Item 1 is described. Although it is stated that the SPCS/SAMS report "is incorporated in entirety into this SAR" we do not find it appended in the posted SAR.

Likes 0	
Dislikes 0	
Response	
David Jendras - 1,3,6	
Answer	No
Document Name	
Comment	

Regarding Item 1: We disagree with changing the word “address” to “consider” in regards to the SPCS/SAMS recommendations. We believe the scope of the effort for item 1 should be limited to what was recommended by SPCS/SAMS. The word “consider” will allow the scope to be enlarged beyond the recommendations from the subject matter experts in the industry – SPCS/SAMS. In our opinion such changes would open the standard to many interpretations, creating significant additional study effort without clear performance-based requirements, which would also lead to future compliance issues. To the extent that the recommendations already identified and documented by SPCS/SAMS represent the best solution(s), further “consideration” by the SDT is not necessary to meet the FERC directives as this would further tie-up industry resources.

While the original FERC Order 754 work was performed with a focus on EHV facilities, there is no language in the SAR that would appear to limit the additional scope of this work in the TPL-001-4 standard to only EHV facilities, for which protection system issues would presumably have a more widespread impact to the BES. The SAR should also include the specific evaluation process and design criteria which were inlcuded in the FERC Order 754 study work. We believe the original intent of Order 754 to target EHV Facilities is a proper allocation of resources in order focus attention on Facilities with the most significant impact to the BES.

Regarding Item 2a: We are concerned with the various categories of contingencies which need to be considered already as part of system assessment work related to compliance with Reliability Standard TPL-001-4, both single and multiple element contingencies, to further give consideration to outages of less than 6 months duration would appear to be needlessly redundant. The six month time frame for including planned outages was intentionally chosen by the TPL Standard Drafting Team to be the correct time frame to make sure that outages which can cover critical peak seasons would be included in the planning analysis. Outages shorter than this are not likely to occur over critical peak seasons. Furthermore, we believe all planned outages are studied by the Operations Planning Department. They will take the necessary steps to operate around an outage. There is no risk to the reliability of the grid if planned outages are not studied (by the Transmission Planner) in planning assessments because the outages are studied by Operations Planning.

Some additional points to consider:

- The purpose of the standard TPL-001-4 is to "Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies". Outages that would be scheduled in the planning horizon would be subject to the performance requirements of this standard. Outages that would be scheduled in the operating horizon should be subject to the performance requirements of other standards.

- Planned maintenance and construction outages typically last from a few days to a few weeks and occur during off-peak time periods with load levels ranging from light load to shoulder peak.

- During the construction and maintenance seasons multiple facilities are out of service at the same time and are studied in the operating horizon.

- System adjustments, including transmission switching and generation redispatch (develop short term operating guides), are made as needed to accommodate planned maintenance and construction outages.

Regarding Item 2b: We believe there is very little risk if stability analysis is not performed for the unavailability of long lead time equipment. 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 outaged element.

Regarding Item 3: No problems are foreseen with updating references relevant to the retirement of MOD-010 and MOD-012.

Likes 0	
Dislikes 0	

Response

David Greene - 10, Group Name SERC PSS

Answer	No
Document Name	

Comment

Regarding Item 1: We disagree with changing the word "address" to "consider" in regards to the SPCS/SAMS recommendations. The scope of the effort for item 1 should be limited to what was recommended by SPCS/SAMS. The word "consider" will allow the scope to be enlarged beyond the recommendations from the subject matter experts in the industry – SPCS/SAMS. To the extent that the recommendations already identified and documented by SPCS/SAMS represent the best solution(s), further "consideration" by the SDT is not necessary to meet the FERC directives as this would further tie-up industry resources.

While the original FERC Order 754 work was performed with a focus on EHV facilities, there is no language in the SAR that would appear to limit the additional scope of this work in the TPL-001-4 standard to only EHV facilities, for which protection system issues would presumably have a more widespread impact to the BES. We believe the original intent of Order 754 to target EHV Facilities is a proper allocation of resources in order focus attention on Facilities with the most significant impact to the BES.

Regarding Item 2a: With the various categories of contingencies which need to be considered already as part of system assessment work related to compliance with Reliability Standard TPL-001-4, both single and multiple element contingencies, to further give consideration to outages of less than 6 months duration would appear to be needlessly redundant. The six month time frame for including planned outages was intentionally chosen by the TPL Standard Drafting Team to be the correct time frame to make sure that outages which can cover critical peak seasons would be included in the planning analysis. Outages shorter than this are not likely to occur over critical peak seasons. Furthermore, we believe all planned outages are studied by the Operations Planning Department. They will take the necessary steps to operate around an outage. There is no risk to the reliability of the grid if planned outages are not studied (by the Transmission Planner) in planning assessments because the outages are studied by Operations Planning.

Some additional points to consider:

1 The purpose of the standard TPL-001-4 is to "Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies". Outages that would be scheduled in the planning horizon would be subject to the performance requirements of this standard. Outages that would be scheduled in the operating horizon should be subject to the performance requirements of other standards.

2 Planned maintenance and construction outages typically last from a few days to a few weeks and occur during off-peak time periods with load levels ranging from light load to shoulder peak.

3 During the construction and maintenance seasons multiple facilities are out of service at the same time and are studied in the operating horizon.

4 System adjustments, including transmission switching and generation redispatch (develop short term operating guides), are made as needed to accommodate planned maintenance and construction outages.

Regarding Item 2b: There is very little risk if stability analysis is not performed for the unavailability of long lead time equipment. 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 outaged element.

Regarding Item 3: No problems are foreseen with updating references relevant to the retirement of MOD-010 and MOD-012.

The comments above are from individial members of the SERC Planning Standards Subcommittee and do not necessarily reflect the positions of SERC or the SERC Board of Directors.

Likes 0	
Dislikes 0	

Response

Katherine Prewitt - 1, Group Name Southern Company

Answer	No
Document Name	

Comment

We disagree with changing the word "address" to "consider" in regards to the SPCS/SAMS recommendations. The scope of the effort for item 1 should be limited to what was recommended by SPCS/SAMS. The word "consider" will allow the scope to be enlarged beyond the recommendations from the subject matter experts in the industry – SPCS/SAMS. To the extent that the recommendations already identified and documented by SPCS/SAMS represent the best solution(s), further "consideration" by the SDT is not necessary to meet the FERC directives as this would further tie-up industry resources.

Likes 0	
Dislikes 0	

Response

John Pearson - 2 - NPCC

Answer	No
Document Name	

Comment

1. While we agree with the overall purpose and changes to the SAR, applying the single point of failure testing to the entire BES is a significant excess that will likely end up with increased spending and very little reliability benefit. It should only be required to be performed on certain facilities, like those the FERC Order 754 test used. This would limit the testing to facilities with the potential for instability, uncontrolled separation, or cascading outages. We recommend the goal 1 of the SAR be modified to:

"Consider the recommendations for modifying NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) as identified in the SPCS and SAMS report titled "Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request", allowing consequential and non-consequential load loss, but not cascading."

In addition, we note that the recent Cost Effectiveness Pilot results show that industry is virtually unanimous in stating that the effect of not considering outages of less than six months is very low risk and and be considered under IRO-017 Outage Coordination. We recommend that goal 2 of the SAR be modified to:

" Address the reliability objectives of the two FERC directives from Order No. 786, which may be able to be accomplished more cost-effectively by considering which, if any, changes are needed to TPL-001, or possibly other NERC standards, such as IRO-017

Likes 0	
Dislikes 0	

Response

Emily Rousseau - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)

Answer	No
Document Name	

Comment

Table 1 footnote 13 Protection System revisions

First, we recommend that the "and open circuit" revision proposed for Table 1 footnote 13 be omitted or the system performance associated with P5 contigencies be revised, unless it can be demonstrated that the inclusion of this criterion and the existing P5 system performance criteria will significantly improve BES reliability and not lead to unreasonable costs.

Most BES substations have a single DC supply and no open circuit monitoring. So, the new open circuit criterion may result in the identification system performance deficiencies at many substations. The corrective action of adding open circuit monitoring may not be feasible and have an unreasonable cost. The corrective action of adding a dual DC supply may also have an unreasonable cost. The initial cost of adding a redundant DC supply at a single station might cost over $500,000 if there is room in the existing control house and even more if the control house has to be expanded. In addition, there is the ongoing cost of peforming the maintenance and testing required by the NERC PRC-005-6 Relibility Standard.

FERC Order 754 conclusions were based on the criteria of both a significant number of transmission interconnections and a 2000 MW stability impact. So, it is reasonable to expect that the addition of the FERC Oder 754 contingency criteria to the TPL-001 standard should have the same system performance criteria as Order 754.

The reliability benefits of the "and open circuit" revision are may be negligible. According to the 2016 NERC State of Reliability Report, DC systems accounted for 5% of NERC protection systems misoperations between 2011 and 2015. And there is no assertion that the system impacts associated with these protection system misoperations were significant.

Second, we also recommend that the "DC control circuitry" proposed for Table 1 footnote 13 be omitted or the system performance associated with P5 contigencies should also be revised, unless it can be demonstrated that the inclusion of this criterion and the existing P5 system performance criteria will significantly improve BES reliability and not lead to unreasonable costs.

Most BES substations have one set of DC control circuity. So, the new DC control circuity criterion may result in identification system performance deficiencies at many substations. The corrective action of adding dual DC control circuit may have an unreasonable cost for the same reasons noted above for adding a dual DC supply.

Six month threshold for planned maintenance outages

As part of the six-month threshold, the SDT should consider giving Transmission Planners and Planning Coordinators flexibility to evaluate planned outages of less than six month duration in combination with "no load loss" planning events (e.g. P1, P2.1, P3, and selected EHV contingencies). The contingency event combinations would be those that risk the loss of a significant amount of firm load or firm transmission service interruption during system off peak load conditions when these shorter planned outages would typically be scheduled.

Likes 0	
Dislikes 0	
Response	
Terry BIlke - 2	
Answer	No
Document Name	
Comment	

MISO believes that planned maintenance outages should be considered in planning for the reliable operation of the BPS. If the planning function does not provide for a robust system with sufficient adequacy to allow each facility an opportunity to be removed from service for planned maintenance during periods when maintenance is typically performed (off-peak) and while simultaneously allowing the system to be operated in a manner that is secure for

N-1 contingencies during the planned outage, the RC outage coordination process could be backed into a corner where they are unable to confidently approve certain maintenance outage requests. Given that a core purpose of planning is to ensure the system is adequate, reliable and robust under future conditions, the need for performing future maintenance of facilities cannot be ignored. However, including only scheduled outages with a 6 month duration or longer will not meet the objective of ensuring the system is adequate to accommodate future maintenance, as this method will not verify that the system will support maintenance of each facility where that facility is required to be removed from service. Therefore, the standard should be revised to remove the 6 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.

As we mentioned in our cost-effectiveness survey response, 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. So removing the 6 month duration requirement in the current standard (which requires a special simulation and cost to complete) and replacing it with the above modification would be effective and require virtually no additional cost.

Likes 0	
Dislikes 0	

Response

Ginette Lacasse - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body

Answer	No
Document Name	

Comment

Seattle City Light SMEs had the following feedback:

Please clarify what components are included in ‘component of a Protection System’. Does this include backup AC and DC protection systems? Does this include a wire and fuses? If redundant relays are fed from a single DC circuit breaker, is it non-redundant? Or are we only speaking of Lock-Out Relays and Aux Relays? Failure of a lockout or aux relays will be interpreted by the tripping relay as a breaker failure, and the trip will be sent out via a different channel. This is modeled in P4.

For Table 1- Steady State & Stability Performance Extreme Events, under the Stability column, No. 2 – The SAR is requesting that four new events are added replacing “a relay failure” with “a component failure of a Protection System”. Once again, if a relay issues a trip, and the fault is not cleared, the breaker failure scheme will operate. These scenarios are currently being studied. What are we trying to address with these new additions?

Need clarification on what a “single point of failure” means with regards to this standard in the larger scheme.

Why does the the planned outage window need to be reduced as this study is included in operations seasonal assessment studies.

Spare transformer consideration is not needed as this is handled with extreme event analysis.

City Light thanks you for taking our comments into consideration.

Likes 0	

Dislikes 0	
Response	
Jeffrey Watkins - 5 - WECC	
Answer	No
Document Name	
Comment	

NV Energy suggests that the revised standard include all components of a protection system and not just the components presently proposed under footnote 13. NV Energy feels that the Transmission Planner should consider all protection system components in its study area and determine which non-redundant protection system component would affect their planning area the most and study it. By limiting which protection system component to study, there is a potential reliability gap by not studying an excluded protection system component.

Likes 0	
Dislikes 0	
Response	
Colby Bellville - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	

At this time, Duke Energy's main concern is to what degree redundancy will be required in the "Protection System," and what all would be included in the "components" of the Protection System.

If the authors of the new document intend to base their requirements on the definitions of redundancy in the 2008 NERC technical paper titled "Protection System Reliability Redundancy of Protection System Elements", a large number of "components" and their current state of implementation would have to be examined/reviewed. This could require a significant volume of work/cost to become compliant based on future document requirements. The following are some questions that would need to be answered::

1. Statement: In current state, many protection and control cables run through a single tray and outdoor trench system.

   Questions/Concerns: To address single component failure, would multiple cable trays or divided cable trays be required? This would potentially be a massive effort to address this issue. A separate secondary trench could be difficult to fit into some entities existing designs.

2. Statement: Many control houses are limited in room and panel space. Many legacy transmission designs have used a single panel for the protection and control of either 1 or 2 transmission lines, or a single panel for 2 bus differential designs. Due to space availability, some entities may use two primary differential systems in one panel and a separate shared secondary in another panel.

   Questions/Concerns: Would future requirements would require the use of 2 panel designs (one for primary and one for secondary protection), and would it be required to have such panels physically separated? In conjunction with separate cabling routing requirements, would the panels have to be lined up on separate rows feeding the separate systems? In order to address this type of a requirement, a significant number of control house additions/replacements would be required.

3. Statement: Many legacy designs use a single DC Panel as well as a single DC source to both primary and secondary protection. While newer designs have used 2 DC sources to the protection (one for primary and one for secondary), many existing substations continue to use one DC panel.

Questions/Concerns: It appears that single DC Panel designs would no longer be acceptable, and all of the legacy DC designs that use a single DC sources in conjunction with fuses to separate DCs for primary and secondary protection would no longer meet a “component” redundancy requirement. This could potentially be a huge undertaking to address existing infrastructure should this become a requirement.

4. Statement: There does not appear to be a clear understanding of when redundant batteries would be required OR what would be an acceptable way to monitor substation battery health.

Questions/Concerns: Would the battery monitoring system need to monitor all cells of the battery? In many cases the health of a battery cannot be determined unless the charger is removed and DC load is placed on the battery; would this be a requirement of the monitoring system?

Until acceptable battery monitoring systems are defined, the scope and magnitude of this requirement cannot be determined.

5. Statement: Pilot communications are a “component” of the protection system. It is unclear what is acceptable and what defines a single component of pilot protection communications.

Questions/Concerns: Are two independent fiber optics run through a single static wire considered separate components, or by being in a single static wire are they considered a single point of failure?

If communication multiplexers are used in the pilot protection, would 2 complete separate communication multiplexer boxes be required to meet the redundancy requirement? Would one multiplexer with 2 independent power supplies be acceptable to meet single component failure requirements? Would one multiplexer with using multiple cards for communication be considered redundant?

6. Statement: Carrier equipment is used in many Directional Comparison Blocking (DCB) protective schemes in transmission. Some entities continue the use of carrier equipment as a reliable means of pilot protection, especially where no other pilot communications are available.

Questions/Concerns: What degree of redundancy would be required on systems using power-line carrier? Would multiple frequency tuners and traps be considered n-2 component failures? If installing multiple sets of tuners and traps to achieve full redundancy becomes required, this could be physically difficult to perform, as well as being financially burdensome.

7. Statement: For the carrier schemes, some entities use frequency shift DCUB, POTT, & BFTT which use up additional frequency band requirements. In the case of BFTT (remote breaker failure trip), some only use one carrier channel for both line schemes.

Question: Should the BFTT channel also be redundant in all cases? Should the local and remote Lockout relays also be separated into redundant schemes?

8. Statement: Many breakers and transformers in service have a limited number of CTs available for protection. In many cases the primary and secondary protection share CTs. Sometimes it is physically impossible to add additional CTs to existing breakers and transformers.

Questions/Concerns: If CT failure is evaluated in these protection systems, it would require the replacement of these breakers and transformers. This would have significant financial impacts, and could take many years to address. Are these types of concerns being addressed by the standard drafting team?

Can different adjacent primary differential schemes share the same CT?

9. Statement: Some entities have existing breakers that use a single trip coil.

Questions/Concerns: Would all of the older breakers with one trip coil require replacement? If an older breaker with one trip coil is replaced with a 2 trip coil breaker, would this mandate a complete protection upgrade that would require the use of both trip coils? Is this correct (it would not appear acceptable to operate a single trip coil design with a 2 trip coils available in a newer breaker)?

10. Statement: Many free standing CTs have multiple cores, and many potential transformers have multiple secondary outputs. Catastrophic failure of a single free standing CT could result in the simultaneous loss of many currents to the protective system. While some of the newer protection installations use two potential transformer outputs independently (one voltage to primary and one to secondary), many do not.

Questions/Concerns: If these types of CTs and Potential Transformers are viewed as a "component" of the protective system and a source of multiple simultaneous impacts to both primary and secondary protective systems, significant upgrades and instrument transformer installations would be required to address risks associated with component failure. This could be an overwhelming task to address these type of component failures.

11. Statement: IT requirements and their redundancy requirements on communications are not clear at this time. Questions/Concerns: Some requirements state that monitoring could alleviate the need for redundancy of a component (example- batteries); what redundancy is required in the monitoring component? Do these types of systems require redundancy in power supply and communications?

Likes 0	
Dislikes 0	

Response

Maryclaire Yatsko - 1,3,4,5,6 - FRCC

Answer	No
Document Name	

Comment

Seminole's comments regarding the proposed SAR, its goal(s), and the newly appointed Standard Drafting Team, includes several items for the team's consideration as they review the existing TPL-001-4 standard in light of Order 754 and single points of failure:

1. Order 754, for most entities, resulted in voluminous amounts of coordination and study work for planning and system protection engineers in evaluating single points of failure, even with a limited scope of including only those facilities that met the criteria of Table 1.1 "Buses to be tested." Seminole requests the drafting team strongly consider the impact of changing the word "relay" with "component of protection system" in light of the Order 754 effort, understanding that a Planning Assessment is required under R1 of TPL-001-4 to be completed annually which may equate to entities having to double up on planning staff to fulfill this increased TPL scope due to what appears to be a harmless word change.

2. If a change is made as a result of the drafting team review, Seminole requests that the drafting team give strong consideration of including a criteria for which buses need to be evaluated as part of the "annual Planning Assessment" for single points of failure, similar to the criteria used in Order 754 rather than using subjective terminology such as "that create the most severe impact."

Seminole requests the following additional item as part of the drafting team scope:

Evaluate R1 of TPL-001-4 to determine what portions of R1 can be removed/retired in light of the newly enforceable MOD-032 standard.

Likes 0	
Dislikes 0	

Response

larry brusseau - 1

Answer	No
Document Name	

Comment

- Table 1 footnote 13 Protection System revisions

First, I recommend that the "and open circuit" revision proposed for Table 1 footnote 13 be omitted or the system performance associated with P5 contingencies be revised, unless it can be demonstrated that the inclusion of this criterion and the existing P5 system performance criteria will significantly improve BES reliability and not lead to unreasonable costs.

Most BES substations have a single DC supply and no open circuit monitoring. So, the new open circuit criterion may result in the identification system performance deficiencies at many substations. The corrective action of adding open circuit monitoring may not be feasible and have an unreasonable cost. The corrective action of adding a dual DC supply may also have an unreasonable cost. The initial cost of adding a redundant DC supply at a single station might cost over $500,000 if there is room in the existing control house and even more if the control house has to be expanded. In addition, there is the ongoing cost of performing the maintenance and testing required by the NERC PRC-005-6 Reliability Standard.

FERC Order 754 conclusions were based on the criteria of both a significant number of transmission interconnections and a 2000 MW stability impact. So, it is reasonable to expect that the addition of the FERC Oder 754 contingency criteria to the TPL-001 standard should have the same system performance criteria as Order 754.

The reliability benefits of the "and open circuit" revision are may be negligible. According to the 2016 NERC State of Reliability Report, DC systems accounted for 5% of NERC protection systems misoperations between 2011 and 2015. And there is no assertion that the system impacts associated with these protection system misoperations were significant.

Second, I also recommend that the "DC control circuitry" proposed for Table 1 footnote 13 be omitted or the system performance associated with P5 contingencies should also be revised, unless it can be demonstrated that the inclusion of this criterion and the existing P5 system performance criteria will significantly improve BES reliability and not lead to unreasonable costs.

Most BES substations have one set of DC control circuity. So, the new DC control circuity criterion may result in identification system performance deficiencies at many substations. The corrective action of adding dual DC control circuit may have an unreasonable cost for the same reasons noted above for adding a dual DC supply.

- Six month threshold for planned maintenance outages

I have some concerns in reference to some of the proposed changes in the SAR. As I stated in my comments for the Cost Effectiveness Pilot SAR (TPL-001-4) in reference to the six (6) month threshold, "I feel by removing the six (6) month threshold, FERC opens the door to annual TPL-001-4 planning assessments being performed for one day outages. Short term outages are considered in operational planning assessments such as seasonal, next-day, and current-day assessments". Additionally, I would be concerned that if I include outages less than 6 months that I might be putting multiple outages in the model that might not really overlap (e.g. 2 one month outages that are planned to be in succession may have to both be in the model shown as being outaged). At this point, I will make the assumption that the 'Cost Effectiveness Pilot' data will serve as support in reference to the concerns in FERC Order 786 pertaining to Paragraph 40 six (6) month threshold issues. With that being said, I would suggest that the drafting team take that the industry's feedback into consideration in reference to the 'Cost Effectiveness Pilot Project' into this current project moving forward.

- Spare equipment strategy for steady state analysis

As for the newly proposed language pertaining to Spare Equipment Strategy for TPL-001-4, I would suggest that the drafting team create an additional requirement for this topic and include it the Standard. I feel adding this language into one of the existing requirements will only cause confusion for the industry. Additionally, I feel that the drafting team needs to implement the proposed language in reference to Spare Equipment Strategy in a new subsection in Requirement 2 section 2.4. This would tie it to Requirement 4 section 4.4 which would lead to the industry developing a contingency list expected to produce more severe system impacts for this stability Spare Equipment Strategy Analysis. Additionally, I would suggest adding some rationale language to help explain the drafting team's intents for the proposed language as well as addressing FERCs concerns in reference to Paragraph 89.

- Updating the MOD references

Finally, I agree with the modification to Requirement R1 pertaining to the retirement of MOD-10 and MOD-12 Standards. The Implementation Plan and the modification reflects consistency with the proposed modification suggested in the Standards Authorization Request (SAR).

Likes 0	
Dislikes 0	
Response	
Andrew Pusztai - 1	
Answer	No
Document Name	
Comment	
ATC supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - 6	
Answer	No
Document Name	

Comment	
PacifiCorp supports changes to the draft SAR as listed in 1) and 3) above. However, PacifiCorp does not support the change in change 2): **2a.)** Planned maintenance outages of less than six months in duration are not necessary for long-term annual planning assessments such as TPL-001-4. The annual TPL-001-4 assessments which look in the near-term (years 1 – 5) and long-term (years 6 – 10) planning horizons are reasonable projections of system conditions and are not meant to represent the specific operational type concerns for outages shorter than six months. Risk is based on probability, duration, and severity. The probability and duration of outages less than six months reduces the chance of an event towards zero as the duration gets smaller. Therefore, the industry reviewed and approved six month duration threshold is appropriate for a planning assessment. By removing the six month threshold, FERC opens the door to annual TPL-001-4 planning assessments being performed for one day outages such as those required for mandated PRC-005-2 relay and maintenance testing. Short term outages are considered in operational planning assessments such as seasonal, next-day, and current-day assessments. Annual Planning Assessments are not operational assessments. In short, annual planning assessments become meaningless as durations become shorter than six months. An annual TPL-001-4 planning assessment represents a reasonable general snapshot of the system assuming all equipment is available and in-service except for the specific contingency performed. Daily operational conditions almost never have the system entirely intact and available due to necessary system maintenance and testing. With respect to the concern for evaluation of planned maintenance outages in the seasonal off-peak periods, inclusion of a requirement to perform an assessment of the off-peak seasonal case for planned maintenance outages with durations greater than six months in duration, that extend into seasonal off-peak periods, may be appropriate for the TPL planning assessment. **2b.)** While stability analysis of equipment with a higher probability of complete failure (transformers, circuit breakers) in the absence of spare inventory may identify practical system risks, stability analysis on equipment with significantly lower probabilities of complete failure (series and shunt capacitors, series and shunt reactors, dynamic reactive support), for which maintaining a spare inventory is impractical, may unnecessarily identify deficiencies that have an exceptionally low risk of occurrence. PacifiCorp recommends NERC complete efforts on the Cost Effectiveness Pilot-2016 to establish a reasonable and supportable threshold for the types of equipment that should be subject to the spare equipment requirement based on probability of failure or some other metric to be determined. PacifiCorp believes that implementation of Order 786, paragraph 89, requiring stability assessment of all equipment with a lead time of one year or more without regard to probability of failure would result in significant administrative, capital and operations and maintenance costs without reasonable justification of the reliability benefit that would be realized by those costs. Specifically, maintaining 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.	
Likes 0	
Dislikes 0	
Response	
Jeff Powell - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
Regarding Item 1:	

TVA believes changing “address” to “consider” would not align with the recommendations of the SPCS and SAMS. The word “consider” may allow for open interpretation of those recommendations resulting in an increase of scope beyond that which is practical.

While the original FERC Order 754 work was performed with a focus on EHV facilities, there is no language in the SAR that would appear to limit the additional scope of this work in the TPL-001-4 standard to only EHV facilities, for which protection system issues would presumably have a more widespread impact to the BES. We believe the original intent of Order 754 to target EHV Facilities is a proper allocation of resources in order focus attention on Facilities with the most significant impact to the BES.

TVA asks the SPCS and SAMS to poll the industry for cost estimates to implement all work required as a result of making these proposed changes to the TPL-001-4 standard. Requiring redundancy of protective relays as well as DC systems could result in significant facility upgrades, including the construction of a new switch house, for all facilities failing to meet planning criteria. The costs associated with these corrective action plans could significantly outweigh the benefits of protecting against these low probablility events.

Regarding Item 2a:

Planned maintenance outages are considered in operational planning studies which assess the reliable operation of the BPS. Multiple contingency studies for off-peak conditions which consider maintenance outages for a single element plus the subsequent unplanned loss of an additional single element are included in TPL-001-4. These studies support system reliability, system maintenance, and operational flexibility. Moreover, additional transmission studies including planned maintenance outages would typically overlap with operational studies. Therefore, TVA sees a low risk to the reliable operation of the BPS if planned maintenance outages of less than six months duration are not considered in TPL-001-4 studies.

Regarding Item 2b:

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. Therefore, TVA sees a low risk to the reliable operation of the BPS if the unavailability of long lead-time equipment is not considered in stability analysis for P0, P1 and P2 events.

Regarding Item 3:

TVA sees no issues with updating references.

Likes 0	
Dislikes 0	

Response

sean erickson - 1,6

Answer	No
Document Name	

Comment

The omission of significant BES outages lasting less than six months from studies as part of the required annual Planning Assessment in accordance with TPL-001-4 is a low risk reliability concern due to Operation Horizon studies and Outage Coordination (IRO-017). However, a slight modification of R1.1.2 is recommended to state: "Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months, or with a duration of less than six months selected by engineering judgment." This small change addresses the perceived reliability concern by codifying current industry practice and grants the flexibility for study performance to the Transmission Planner.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
Our review group has some concerns in reference to some of the proposed changes in the SAR. As we stated in our comments for the Cost Effectiveness Pilot SAR (TPL-001-4) in reference to the six (6) month threshold, "we feel by removing the six (6) month threshold, FERC opens the door to annual TPL-001-4 planning assessments being performed for one day outages. Short term outages are considered in operational planning assessments such as seasonal, next-day, and current-day assessments". Additionally, we would be concerned that if we include outages less than 6 months that we might be putting multiple outages in the model that might not really overlap (e.g. 2 one month outages that are planned to be in succession may have to both be in the model shown as being outaged). At this point, we will make the assumption that the 'Cost Effectiveness Pilot' data will serve as support in reference to the concerns in FERC Order 786 pertaining to Paragraph 40 six (6) month threshold issues. With that being said, we would suggest that the drafting team take that the industry's feedback into consideration in reference to the 'Cost Effectiveness Pilot Project' into this current project moving forward. As for the newly proposed language pertaining to Spare Equipment Strategy for TPL-001-4, we would suggest that the drafting team create an additional requirement for this topic and include it the Standard. We feel adding this language into one of the existing requirements will only cause confusion for the industry . Additionally, the review group feel that the drafting team needs to implement the proposed language in reference to Spare Equipement Strategy in a new subsection in Requirement 2 section 2.4. This would tie it to Requirement 4 section 4.4 which would lead to the industry developing a contingency list expected to produce more severe system impacts for this stability Spare Equipment Strategy Analysis. Additionally, we would suggest adding some rationale language to help explain the drafting team's intents for the proposed language as well as addressing FERCs concerns in reference to Paragraph 89. Finally, we agree with the modification to Requirement R1 pertaining to the retirement of MOD-10 and MOD-12 Standards. Our group reviewed the Implementation Plan and the modification reflects consistency with the proposed modification suggested in the Standards Authorization Request (SAR).	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - 2, Group Name IRC Standards Review Committee	
Answer	No

Document Name	
Comment	

(a) Paragraph 40 Directive

The ISO/RTO Council (SRC) Standards Review Committee (SRC) acknowledges that the SDT must address the two outstanding directives from FERC Order No. 786. However, revising TPL-001-4 to address these two directives is unnecessary.

First, Order No. 786 directs NERC to address the concern that excluding planned maintenance outages less than six months in duration in the TPL-001-4 assessment could potentially impact bulk electric system reliability. The SRC agrees that planned maintenance outages should be considered in planning for the reliable operation of BPS. However, outages less than six months in duration discussed in the FERC order are already accounted for in grid planning during the outage coordination process in the operational planning horizon.

Reliability Coordinators (RCs) consider requests for planned maintenance outage submitted by entities in their respective RC areas through their outage coordination procedures. Each RC presently has the authority to deny any planned maintenance outages that would create reliability risks and thereby mitigate any potential risks resulting from planned maintenance outages in its RC area. Reliability Standard IRO-017-1 – *Outage Coordination*, effective April 1, 2017, codifies this practice by requiring RCs to establish a generation and transmission outage coordination process. Consequently, there is no risk to the reliable operation of the BPS if planned maintenance outages of less than six months in duration are not considered in planning studies during one or both seasonal off-peak periods under the TPL-001-4 standard. Also, even if these outages weren't already managed through outage coordination, requiring planners to consider them in transmission planning studies may not be helpful anyway, since a significant number of planned maintenance outages conducted in any given year will not be scheduled or submitted for approval far enough in advance to be incorporated into the planning assessment required under TPL-001-4.

Furthermore, requiring planners to study these outages could result in the identification of costly transmission upgrades to address needs that are expected to be temporary. For this reason, outage coordination is a much more cost-effective option for addressing these outages.

The SRC recommends that the SDT address FERC's directive in Order 786 by requiring that Transmission Planners and Planning Coordinators evaluate planned maintenance outages of less than six months in duration only if the RC for the RC area in which the facilities subject to the Planning Assessment are located does not already coordinate outages for those facilities.

(b) Paragraph 89 Directive*

Second, Paragraph 89 in Order No. 786 directs NERC to "consider" whether it should modify TPL-001-4 to include potential outages of long-lead-time equipment in stability analyses for the P0, P1 and P2 categories identified in Table 1. A revision to TPL-001-4 to address this concern is unnecessary because TPL-001-4 already requires entities to perform stability analyses for the P3 through P7 categories, which produce the same contingency results that stability analyses for P0 and P1 categories would produce assuming unavailability of long-lead-time equipment. While SRC acknowledges that stability analyses of P3 through P7 conditions do not currently include the multiple contingency loss of long-lead-time equipment coupled with the fault conditions described in P2, requiring these additional stability analyses would not be cost-effective because these conditions have historically been very infrequent. For this reason, it is unnecessary and inappropriate to require the proposed analysis.

(c) Single Points of Failure

While we agree with the overall purpose and changes to the SAR, applying the single point of failure testing to the entire BES is a significant excess that will likely end up with increased spending and very little reliability benefit. It should only be required to be performed on certain facilities, like those the FERC Order 754 test used. This would limit the testing to facilities with the potential for instability, uncontrolled separation, or cascading outages. We recommend the goal 1 of the SAR be modified to: “Consider the recommendations for modifying NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) as identified in the SPCS and SAMS report titled “Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request”, allowing consequential and non-consequential load loss, but not cascading.”

*The IESO does not sign on to the comments addressing the Paragraph 89 directive.

** Please note that MISO and CAISO do not sign on to these comments.

Likes 0	
Dislikes 0	
Response	

Terry Harbour - 1,3	
Answer	No
Document Name	
Comment	

MidAmerican supports the MRO NSRF comments in general with the following additions.

We recommend that the “and open circuit” revision proposed for Table 1 footnote 13 be omitted or the system performance associated with P5 contigencies be revised unless it can be demonstrated that the inclusion of this criterion and the existing P5 system performance criteria will significantly improve BES reliability and not lead to unreasonable costs. NERC needs to clearly articulate the BES risk being addressed with the "open circuit" battery monitoring and / or the dual battery banks. If the risk is related to battery capacity, then a dual battery bank mandate may be costly and may not correct the issue. If the risk is an open battery circuit, the open circuit presents a significant risk, and the open circuit monitoring corrects that risk, then the proposal may be appropriate. The reliability benefits of the “and open circuit” revision for battery monitoring may be negligible. According to the 2016 NERC State of Reliability Report, DC systems accounted for 5% of NERC protection systems misoperations between 2011 and 2015 and there is no assertion that the system impacts associated with these protection system misoperations were significant.

We recommend that the “DC control circuitry” proposed for Table 1 footnote 13 be omitted or the system performance associated with P5 contigencies should also be revised, unless it can be demonstrated that the inclusion of this criterion and the existing P5 system performance criteria will significantly improve BES reliability and not lead to unreasonable costs.

Most BES substations have one set of DC control circuity. Recent State of Reliability report did not articulate what impact DC control circuits have on misoperations, so the corrective action of adding dual DC control circuit may have an unreasonable cost for little to no benefit.

We recommend that removing the six-month TPL-001-4 planning assessment threshold is not cost effective and the FERC directive in paragraph 40 of Order No. 786 relating to TPL-001-4 should not be implemented. We suggest an impa equally effective alternative be proposed to address FERC's concerns about off-peak conditions. Existing wording in the NERC standard could be identified or clarified to state "outages of more than six-months should include a sensitivity analysis if the outage occurs in the spring and / or fall months."

By removing the six month threshold, FERC opens the door to annual TPL-001-4 planning assessments being performed for one-day outages such as those required for mandated PRC-005-2 relay and maintenance testing. Short term outages are considered in operational planning assessments such as seasonal, next-day, and current-day assessments. Annual Planning Assessments are not operational assessments. In short, annual planning assessments become meaningless as durations become shorter than six months. An annual TPL-001-4 planning assessment represents a reasonable general snapshot of the system assuming all equipment is available and in-service except for the specific contingency performed. Daily operational conditions almost never have the system entirely intact and available due to necessary system maintenance and testing.

Likes 0	
Dislikes 0	

Response

Leonard Kula - 2

Answer	Yes
Document Name	

Comment

The IESO generally agrees with the proposed changes to the scope of the SAR. Nevertheless, as indicated in our comments on the previous SAR, some of the proposed changes to TPL-001-4 described in the SAR are unclear. Hence, we reserve our judgment on the final scope and the specific changes that will be made to the TPL-001-4 standard. For example:

1. **The replacement of FN 13 with the proposed wording but there is no mention of the placement of the functions or types of relay that will be replaced.**

2. **The meaning of "evaluation of the three-phase faults the described component failures of a Protection System" in the last bulleted proposed change is unclear. Does it mean evaluation of a three phase fault combined with the component failure of a Protection System? This needs to be clarified.**

3. **The SAR is unclear on the fault locations that need to be assessed to meet the following objective:**

"Modify TPL-001-4 (Part 4.5) so that extreme event assessments must include evaluation of the three-phase faults with the described component failures of a Protection System13 that produce the more severe system impacts.

Generally, in planning studies, the three-phase faults that are assessed are located on the buses or in their vicinity on the circuits since they have more severe system impact. These faults can still be cleared remotely while the local protection systems experience a component failure.

When the three-phase faults are moved along the circuits there may be locations where the faults remain un-cleared since the protection systems (including the back-up ones) may not be able to detect the faults while they experience a component failure.

Is the intention of the SAR to identify the fault locations where the three-phase faults will remain un-cleared while the protection systems experience a component failure?

The IESO would appreciate the final SAR having more clarity on the above issues.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - 3,5

Answer	Yes
Document Name	

Comment

AEP considers the perceived risk of not considering planned maintenance outages less than six months in duration in its studies to be minimal (as previously stated in our comments for the Cost Effectiveness Pilot). At present, our Operations team (in conjunction with applicable RCs) addresses these short duration issues in both real time and seasonal analysis. It would be impractical to address short duration maintenance outages as part of long term planning and modeling. As a result, we do not believe there is a risk-based need to adjust the threshold to less than six months in system models.

As stated in our comments for the previous comment period on this project, the SDT should emphasize both feasibility and practicality in any future requirements regarding system modeling, and the implementation thereof.

Use of the term “include” in the revised footnote 13 may be a source of confusion about whether the other two Protection System components (communication systems, voltage and current sensing devices) are also required by the TPL standard. Rather than “include, we recommend instead using “are” in the revised footnote 13.

We would further recommend not qualifying a NERC Glossary term by footnoting the term “Protection System.” It would be preferable to simply state which components are applicable in Table 1 itself.

While “Single Point of Failure” may have been the original driver for this project, the directives within the SAR now appear to be fairly diverse. Because of this widened scope, the SDT may wish to consider adopting a new project title, one that more clearly specifies their objectives.

The recent comment period for the Cost Effectiveness Pilot for Project 2015-04 (TPL-001-4) included the following guidance: “Project 2015-10: Single Points of Failure TPL-001 from the 2016-2018 Reliability Standards Development Plan is developing a SAR to address potential modifications to TPL-001-4. The results of this pilot will be provided to the drafting team to inform their work on modifying this standard.” The due date for comments for Project 2010-04 was 5/26, which turned out to also be the kickoff date for Project 2015-10. How is it possible that comments for Project 2015-04 could be used to further develop the Project 2015-10 SAR, given that there were no calendar days separating the two comment periods?

Likes 0	
Dislikes 0	

Response

John Brockhan - 1

Answer	Yes
Document Name	
Comment	

CenterPoint Energy agrees the two (2) outstanding FERC directives from FERC Order No. 786 should be addressed; however, CenterPoint Energy believes the Standard Drafting Team can address the two directives in other ways than modifying Reliability Standard TPL-001-4. CenterPoint Energy comments submitted for the Cost Effectiveness Pilot related to this project included the following:

- CenterPoint Energy does not see risks associated with the current six-month threshold for modeling known outages of generation or Transmission Facility(ies) as specified in TPL-001-4 R1.1.2. Planned maintenance outages of generation or Transmission Facility(ies) with a duration of at least six months are rarely, if ever, scheduled far enough in advance to be included in the Near-Term Transmission Planning Horizon. Shortening the timeframe would only decrease the likelihood of identifying a relevant outage. However, TPL-001-4 R2.1.4 allows for sensitivity analysis to be performed for outages less than six months in duration. If such outages are deemed potentially critical to system reliability, they may be included in the assessment under the current Standard. Furthermore, outages of less than six months reflect operational scenarios and are considered in required operational planning assessments.

- CenterPoint Energy does not believe there is any risk because the impact of the unavailability of long lead time equipment for TPL-001-4 Category P0, P1 and most P2 conditions is already captured as part of the Category P6 stability analysis.

Likes 0	
Dislikes 0	
Response	

Rachel Coyne - 10

Answer	Yes
Document Name	
Comment	

While Texas RE believes that the scope of the proposed project set forth in the revised SAR appropriately includes the SPSC and SAMS recommendations contained in the Order No. 754 Assessment of Protection System Single Points of Failure report and the FERC directives from FERC Order No. 786, Texas RE remains concerned that the overall scope of this project is too limited. Specifically, Texas RE supports those commenters, such as XCEL, that have suggested that the scope of this project include consideration of any significant issues, reliability gaps, and policy concerns identified through the implementation of the existing TPL-001-4 Standard. Texas RE requests the SDT consider areas in which the existing Standard can be improved, clarified, or expanded as necessary to address reliability issues as they are identified throughout the course of this project.

Consistent with this comprehensive look at the TPL-001-4 Standard, Texas RE also urges the SDT to consider the impact of changes in this Standard on other requirements and definitions. Texas RE previously submitted the comment that it is concerned the proposed language for footnote 13 in TPL-001-4 does not match the NERC Glossary term for Protection System. The language proposed in the SAR for “protective relays” and “DC control circuitry” largely tracks the definition of “Protection System” set forth in the NERC Glossary of Terms. The sole substantive distinction appears to be limiting the general category of “control circuitry” explicitly to “DC control circuitry” consistent with recommendation in the Order No. 754 Report.

In contrast, the SAR (and the Order No. 754 Report) places additional, qualifying language on the definition of “station DC supply” that is not contained in the definition of Protection System in the NERC Glossary of Terms. Specifically, the “Protection System” definition in the NERC Glossary of Terms includes: “Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery based dc supply).” The SAR (and the recommended language in Order No. 754 Report) qualifies this language by describing “station DC supply” as “single-station DC supply that is not monitored (i.e., not reported within 24 hours of detecting an abnormal condition to a location where corrective action can be initiated).”

Texas RE recommends that the SDT use of the existing definition of station DC Supply in the NERC Glossary of Terms. Using consistent language in both Standards would help entities classify their dc supply components in a uniform manner across their compliance program.

Likes 0	
Dislikes 0	
Response	

Colleen Campbell - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	

(1) We generally agree with the expanded scope and intent of this project, particularly with the modification to requirements and Violation Severity Levels associated with the retirement of MOD-10 and MOD-12 standards. However, there still remains ambiguity in the attributed compliance responsibilities between Planning Coordinators and Transmission Planners in this standard. We recognize the necessary coordination between both functional roles, although clarification should be added to define which functional role is responsible.

(2) We have concerns regarding interpretations of the two directives in Order No. 786 meant to address 1) additional contingency studies to include protection components as “spare equipment,” and 2) changes to the six-month threshold to include planned maintenance outages of significant facilities in future planning assessments. There is concern that by removing the six-month threshold, operational planning assessments may be required and create a substantial cost burden on the industry. We ask the SDT to refer to industry feedback associated with the “Cost Effectiveness” project when developing this aspect of the standard and provide sufficient clarification around planning assessment expectations. Regarding studies that include a spare equipment strategy component, we believe the SDT should limit their response to the directive to only substation power transformers before including other BES Elements. Moreover, we believe the SDT should incorporate this additional component in a new requirement and avoid the revision of existing stability analysis requirements.

(3) We sustain our previous concerns that the current applicability of this standard is inclusive to all BES Elements, not the sub-set identified and analyzed as part of the Section 1600 Data Request. The findings identify that buses under 300 kV are less likely to result in an adverse impact to BES reliability based from a Protection System single point of failure. Proposing to collect data for all BES Elements poses an unnecessary administrative burden on registered entities and their models, especially considering that the findings do not support additional analysis under 300 kV. Moreover, analysis results identifying issues which adversely impact the BES reliability could be masked by insignificant concerns.

(4) Within the proposed SAR, we identify several misspellings with words like “consideration” or “cited,” and alert the SDT to correct these errors prior to NERC Standards Committee approval.

(5) We thank you for your time in developing this revision to the SAR and the opportunity to provide these comments.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - 1,2,3,4,5,6,7 - NPCC, Group Name RSC no ISO-NE, IESO	
Answer	Yes
Document Name	
Comment	
In the Section Identify the Objectives of the proposed standards' requirements (What specific reliability deliverables are required to achieve the goal?): correct the spelling of consideration, and cited. In the Detailed Description Section under SAR Information on page 4, in the second sentence "in" should not be struck out.	
Likes 0	
Dislikes 0	
Response	
Nick Vtyurin - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andy Bolivar - 1,3,4,6 - FRCC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Laura Nelson - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - 1 - MRO,SPP RE,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - NA - Not Applicable - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	