Comment Report

Project Name:	2015-10 Single Points of Failure | TPL-001-5
Comment Period Start Date:	4/25/2017
Comment Period End Date:	5/24/2017
Associated Ballots:	

There were 63 sets of responses, including comments from approximately 180 different people from approximately 129 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with the proposed changes to Requirement 1, Part 1.1.2 that move away from the 6 month duration outage to limited known outages selected by the Planning Coordinator (PC)/Transmission Planner (TP) in consultation with their Reliability Coordinators (RCs) for the time horizon of the operations planning horizon through the near term planning horizon?

2. Do you agree with the proposed changes to Requirement 2, Part 2.4.5 which addresses the Federal Energy Regulatory Commission (FERC) order to add the spare equipment with long lead time to the dynamics analysis?

3. Do you agree with the further clarification of relay to components of a Protection System with the additional footnote to clarify P5 and extreme events?

4. Do you agree with the proposed Requirement 4, Part 4.6 additions which require a Corrective Action Plan for this subset of Table 1 extreme events (footnote 13, 2e-2h)?

5. Do you agree with the drafting team's approach which doesn't add additional applicable entities to the applicability of the standard? (e.g. RC, Transmission Operator (TO), Generator Operator (GO), Distribution Provider (DP))

6. Do you agree with the 36 month implementation period to address All Requirements except for Requirement R4, Part 4.6, and Requirement 2, Part 2.7 associated with P5 due to Footnote 13 bullets 2, 3 and 4, as well as the definitions?

7. Do you agree with the 60 month implementation plan for Requirement 4, Part 4.6 and Requirement 2, Part 2.7 associated with P5 due to Footnote 13 bullets 2, 3 and 4?

8. Are you aware of any other governing documents that could be in conflict with the current proposal for this draft of the standard?

9. Do you agree with the teams proposed changes to align the VRF/VSLs for Requirement 4, Part 4.6 with the VRF/VSLs for Requirement 2, Part 2.7?

10. Do you have any other general recommendations / considerations for the drafting team?

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Portland General Electric Co.	Angela Gaines	1,3,5,6	WECC	PGE - Group 1	Angela Gaines	Portland General Electric Company	3	WECC
					Barbara Croas	Portland General Electric Company	5	WECC
					Scott Smith	Portland General Electric Company	1	WECC
					Adam Menendez	Portland General Electric Company	6	WECC
Independent Electricity System Operator	Ben Li	2	NPCC	ISO/RTO Council Standards Review Committee	Charles Yeung	SPP	2	SPP RE
					Greg Campoli	NYISO	2	NPCC
					Ali Miremadi	CAISO	2	WECC
					Ben Li	IESO	2	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC
					Nathan Bigbee	ERCOT	2	Texas RE
ACES Power Marketing	Brian Van Gheem	6	NA - Not Applicable	ACES Standards Collaborators	Greg Froehling	Rayburn Country Electric Cooperative, Inc.	3	SPP RE
					Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	RF
					John Shaver	Arizona Electric Power Cooperative, Inc.	1	WECC

					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Ginger Mercier	Prairie Power, Inc.	1,3	SERC
					Steve McElhaney	CooperativeEnergy	4,6	SERC
					Shari Heino	Brazos Electric Power Cooperative, Inc.	1,5	Texas RE
					Matthew A. Caves	Western Farmers Electric Cooperative	1,5	SPP RE
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
Seattle City Light	Ginette Lacasse	1,3,4,5,6	WECC	Seattle City Light Ballot Body	Pawel Krupa	Seattle City Light	1	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	1,4	WECC
					Faz Kasraie	Seattle City Light	5	WECC
					John Clark	Seattle City Light	6	WECC
					Tuan Tran	Seattle City Light	3	WECC

					Laurrie Hammack	Seattle City Light	3	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
Associated Electric Cooperative, Inc.	Mark Riley	1,3,5,6		AECI & Member G&Ts	Mark Riley	Associated Electric Cooperative, Inc.	1	SERC
					Brian Ackermann	Associated Electric Cooperative, Inc.	6	SERC
					Brad Haralson	Associated Electric Cooperative, Inc.	5	SERC
					Todd Bennett	Associated Electric Cooperative, Inc.	3	SERC
					Michael Bax	Central Electric Power Cooperative (Missouri)	1	SERC
					Adam Weber	Central Electric Power Cooperative (Missouri)	3	SERC
					Ted Hilmes	KAMO Electric Cooperative	3	SERC
					Walter Kenyon	KAMO Electric Cooperative	1	SERC
					Stephen Pogue	M and A Electric Power Cooperative	3	SERC
					William Price	M and A Electric Power Cooperative	1	SERC

					Mark Ramsey	N.W. Electric Power Cooperative, Inc.	1	SERC
					Kevin White	Northeast Missouri Electric Power Cooperative	1	SERC
					Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	3	SERC
					John Stickley	NW Electric Power Cooperative, Inc.	3	SERC
					Jeff Neas	Sho-Me Power Electric Cooperative	3	SERC
					Peter Dawson	Sho-Me Power Electric Cooperative	1	SERC
Lower Colorado River Authority	Michael Shaw	1,5,6		LCRA Compliance	Teresa Cantwell	LCRA	1	Texas RE
					Dixie Wells	LCRA	5	Texas RE
					Michael Shaw	LCRA	6	Texas RE
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no ISO-NE, NYISO and NextEra	Paul Malozewski	Hydro One.	1	NPCC
					Guy Zito	Northeast Power Coordinating Council	NA - Not Applicable	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	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	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Sylvain Clermont	Hydro Quebec	1	NPCC
					Si Truc Phan	Hydro Quebec	2	NPCC
					Helen Lainis	IESO	2	NPCC
					Laura Mcleod	NB Power	1	NPCC
					Michael Forte	Con Edison	1	NPCC
					Kelly Silver	Con Edison	3	NPCC
					Peter Yost	Con Edison	4	NPCC
					Brian O'Boyle	Con Edison	5	NPCC
					Michael Schiavone	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC
					David Ramkalawan	Ontario Power Generation Inc.	5	NPCC
					Quintin Lee	Eversource Energy	1	NPCC

					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
Midwest Reliability Organization	Russel Mountjoy	10		MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
					Chuck Lawrence	American Transmission Company	1	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administratino	1,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Mahmood Safi	Omaha Public Power District	1,3,5,6	MRO
					Brad Parret	Minnesota Power	1,5	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Tom Breene	Wisconsin Public Service	3,5,6	MRO
					Jeremy Volls	Basin Electric Power Coop	1	MRO
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Mike Morrow	Midcontinent Independent System Operator	2	MRO

Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					Deborah McEndafffer	Midwest Energy, Inc	NA - Not Applicable	NA - Not Applicable
					Robert Gray	Board of Public Utilities (BPU) Kansas City, Kansas	3	SPP RE
					Rober Hirchak	Cleco	1,3,5,6	SPP RE
					Ellen Watkins	Sunflower Electric Power Corporation	1	SPP RE
					Jim Nail	City of Independence, Power and Light Department	5	SPP RE
					John Allen	City Utilities of Springfield, Missouri	4	SPP RE
					Jonathan Hayes	Southwest Power Pool, Inc	2	SPP RE
					Kevin Giles	Westar Energy	1	SPP RE
					Liam Stringham	Sunflower Electric Power Corporation	1	SPP RE
					Louis Guidry	Cleco	1,3,5,6	SPP RE
					Michelle Corley	Cleco Corporation	3	SPP RE
					Mike Kidwell	Empire District Electric Company	1,3,5	SPP RE
					Steve McGie	Board of Public Utilities (BPU) Kansas City, Kansas	3	SPP RE

					J. Scott Williams	City Utilities of Springfield, Missouri	1,4	SPP RE
					Joe Fultz	Grand River Dam Authority	1	SPP RE
					Thomas Maldonado	Excel Energy	NA - Not Applicable	SPP RE
Santee Cooper	Shawn Abrams	1,3,5,6		Santee Cooper	Tom Abrams	Santee Cooper	1	SERC
					Rene' Free	Santee Cooper	1	SERC
					Weijian Cong	Santee Cooper	1	SERC
					Chris Wagner	Santee Cooper	1	SERC
					Anthony Noisette	Santee Cooper	1	SERC
PPL NERC Registered Affiliates	Shelby Wade	1,3,5,6	RF,SERC	PPL NERC Registered Affiliates	Charlie Freibert	LG&E and KU Energy, LLC	3	SERC
					Brenda Truhe	PPL Electric Utilities Corporation	1	RF
					Dan Wilson	LG&E and KU Energy, LLC	5	SERC
					Linn Oelker	LG&E and KU Energy, LLC	6	SERC

1. Do you agree with the proposed changes to Requirement 1, Part 1.1.2 that move away from the 6 month duration outage to limited known outages selected by the Planning Coordinator (PC)/Transmission Planner (TP) in consultation with their Reliability Coordinators (RCs) for the time horizon of the operations planning horizon through the near term planning horizon?

Leonard Kula - Independent Electricity System Operator - 2

Answer	No

Document Name	
Comment	

There are a few concerns that are introduced by the proposed modification of part 1.1.2:

- Order 786 specifically mentions that TPL-001 is intended to analyze the Near-Term Transmission Planning Horizon and requires annual assessments using Year One or year two, and year five. However, outages planned to occur within the next 12-months should be analyzed per the Operations Planning requirements of IRO-017 which is intended to cover the Operations Planning time horizon. Therefore, only outages planned for this timeframe (more than 12-months forward) in advance are appropriate to be required to be analyzed as a requirement of a Transmission Planning standard such as TPL-001 and the standard should not involve the RC.

- Moving from a firm threshold to consultation creates ambiguity and potential reliability gaps, and is not an effective means to address the FERC concerns expressed in Order 786. when there are no criteria as to how that consultation is to proceed.

- Replacing the 6-month threshold with a consultation with the RC has the following potential shortfalls:

    1. The TP’s/PC’s footprint is not necessarily the same as the RC’s; there can be several RCs within a TP/PC area, or the other way around. In these cases, who should be consulted and how to reach an agreement if multiple entities are involved? And on what basis should the RC(s) recommend inclusion of certain planned outages?

    2. While the draft standard places an obligation on the TP/PC to consult, there is no mirror obligation on the RC to respond. What if the RC does not respond? Is the TP/PC held non-compliant for having no planned outages included in the planning assessment?

    3. Two entities may be assessing the same system conditions included the planned outages, but they could come up with quite different assessment results due to different risk tolerances or approaches applied in the assessment. If the TP/PC and the RC, or multiple RCs when more than one is involved, come up with different assessment results, whose results should prevail?

To address the FERC directive without the above potential reliability gaps or shortfalls, we offer the following suggestions:

1. Conduct sensitivity testing to identify those planned outages with a duration of more than 1 month but less than 6 months that can have a reliability impact in the planning horizon, and

2. Reflect them in the base model along with those planned outages with a duration of 6 months or longer.

The above can be achieved by revising Part 1.1.2, returning Part 2.1.3 to the existing wording and adding a bullet under Part 2.1.4, as follows:

Part 1.1.2: Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months, and those planned outages identified through sensitivity testing in Part 2.1.4 as having a reliability impact in the planning assessment horizon. Part 2.1.3: P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled. Part 2.1.4: Adding the bullet at the end of the list: • Planned outages of generation or transmission Facility(ies) with a duration of more than 1 month but less than 6 months.	
Likes 0	
Dislikes 0	
Response	
Robert Ganley - Long Island Power Authority - 1	
Answer	No
Document Name	
Comment	
We do not agree with the concept of removing the 6 month duration outage and we have concerns with the idea of consultation with the Reliability Coordinator (RC). We also disagree with the contention that N-1-1 analyses as specified by P3 and P6 events are not sufficient to address the near term planning horizon reliability concern. The 6 month known outage duration in the existing standard version, while possibly arbitrary to reliability, does provide some level of objectivity when identifying outages. In contrast, the proposed language is too subjective and open to interpretation. The idea of consulting with the RC to identify known outages, while possibly relevant, adds to the lack of objectivity in identifying known outages and increases the level of complexity in identifying known outages. This idea also does not provide clear ownership for the identification of known outages. In summary, we feel the 6 month known outage duration in the existing standard version balances objectivity and complexity. As an alternative, we would suggest the SDT investigate the possibility of taking a step back and altering this specific requirement to make it applicable to the TOP and also the TP. The TOP may be in the best position to be aware of known / planned outages in the near term planning horizon, and to be able to identify such outages to the TP. As stated in the rationale, the goal is not to consider hypothetical outages. The TOP may be in the best position to identify	

known / planned outages, prioritize them in terms of reliability impact, and then them provide to the TP for analysis in the annual near term planning horizon planning assessment.

Regarding the stated contention that N-1-1 analyses as specified by P3 and P6 events are not sufficient to address the near term planning horizon reliability concern, we would disagree. In practice, P3 and P6 should be sufficient as a proxy to assess the impact of an outage followed by another P1 event, as required by Req #2.1.3. The intent of R2.1.3 is to model an outage as an N-0 condition, and then apply and assess a P1 event.

For this same reason, we do not agree with the new proposed Req #2.4.3 (stability analysis considering known outages). In practice, this modified requirement is somewhat redundant with Table 1, P3 and P6 events. P3 and P6 events are applicable for stability analysis. The additional study burden (or compliance burden) may not be commensurate with the expected incremental reliability benefit. If this requirement will be maintained, then the wording should be consistent with the modified requirement 2.1.3.

Finally, It appears there may be a wording error in the modified Req #2.1.3. Req # 2.1.3 should be modified / clarified to state that "P1 events in Table 1, as selected in consultation with the as directed Reliability Coordinator, with the known outages modeled as specified in Requirement R1, Part 1.1.2 (outages selected in consultation with the Reliability Coordinator) under those System peak or Off-Peak conditions when known outages are scheduled." Our understanding is that the objective is to have the RC consult in the selection of known outages, and not necessarily in the selection of P1 events.

Likes 0	
Dislikes 0	

Response

Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6

Answer	No
Document Name	

Comment

The new requirement does not address a scenario where the TP does not agree with the RC regarding what needs to be studied, or how such a disagreement would be managed from the compliance perspective. The "limited known outages" statement in Question 1 is not part of R1.

We recommend the Requirements 1.1.2 and 2.1.3 be revised as follows to clarify which entity has the sole responsibility to select the outages (additions in **BOLD**):

R1.1.2 Known outage(s) of generation or Transmission Facility(ies) as selected **by the Transmission Planner following** consultation with the Reliability Coordinator for the Near-Term **Transmission** Planning Horizon for analyses pursuant to Requirement R2, parts 2.1.3 and 2.4.3. R2.1.3. P1 events in Table 1, as selected **by the Transmission Planner following** consultation with the Reliability Coordinator, with known outages modeled as specified in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled. Alternatively RC should be removed from these Requirements and TP should have the flexibility to select what needs to be studied; as it relates to outages. In addition, this new requirement would result in Transmission Planners (TP) performing an annual study as the RC could request a study to review upcoming outages. This could result in a conflict with the existing Requirements that allow the use of past studies to satisfy compliance with TPL-001.	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1,3,5	
Answer	No
Document Name	
Comment	
We are comfortable with the move away from the 6 month minimum duration outage requirement. However, we feel strongly that the outages selected by the PC/TP in consultation with their RC should be limited to known outages for the time period beyond 12-months from the current date to year 5. Since the proposed revision uses the term 'Near-Term Planning Horizon' this would inadvertently include the first year which is an Operational Planning responsibility. The TPL-001 standard is intended for Transmission Planning, not Operations Planning, and is focused on analyzing the transmission system for necessary upgrades to maintain reliability. These upgrades require well over 12-months to plan, design, permit, and construct. Required analysis of outages planned in the timeframe of less than 1 year from the current date should be the exclusive responsibility of Operations Planning through reliability standards such as IRO-017 which are intended to cover the Operations Planning time horizon	
Likes 0	
Dislikes 0	
Response	

Bridget Silvia - Sempra - San Diego Gas and Electric - 1,3,5	
Answer	No
Document Name	
Comment	

SDG&E reads the sentence, "in consultation with the Reliability Coordinator", to mean that the Transmission Planner and Planning Coordinator would be required to have the list of maintenance outages assessed approved by its Reliability Coordinator [PeakRC]. This would shift some of the responsibility for TPL-001 from the TP/PC to the RC and it is unlikely that an RC would approve a list of know outages which did not include all know outages (a subset of the complete list) without first assessing each outage on the list. Requiring the RC to approve ***all*** *known outages within its territory will place an unreasonable burden on the RC and the TPs/PCs. SDG&E recommends removing the language, "in consultation with the Reliability Coordinator" from 1.1.2 and 2.1.3.*

SDG&E agrees with the addition of section 2.4.3. The original language in requirement R1.3.12 read, "Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed." This language is reflected in 2.4.3 and serves to limit the study of known – planned - outages to those periods when maintenance is typically done (Off-peak load periods). It also captures known outages of long duration which may not be completed before the next peak load period occurs (System peak load).

Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 3,5	
Answer	No
Document Name	
Comment	

While AEP does not object outright to the proposed change that the outages be determined as a result of consultation between the PC/TP and RC, we wonder if such an approach might perhaps lead to inconsistent application and methodologies across the system? The Standards Drafting Team may wish to consider this possibility themselves, and weigh the likelihood of such inconsistencies. The text "as selected in consultation with the Reliability Coordinator" has been inserted at the wrong location within R.2.1.3. As currently proposed, it appears that it the P1 events, rather than the outages themselves, which are being selected in consultation with the Reliability Coordinator.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA agrees with moving away from the 6-month fixed duration outages. BPA does not agree that consultation with the Reliability Coordinator is necessary. BPA believes the extra coordination would be burdensome and would not provide additional value. BPA already participates in a 45 day regional outage coordination process. BPA believes that this regional coordination process is sufficient to identify the outages to meet Requirement 1, Part 1.1.2.	
Likes 0	
Dislikes 0	
Response	
Jeff Powell - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No

Document Name	
Comment	

TVA does not agree with the change to Requirement 1, Part 1.1.2. The Planning Coordinator and Transmission Planners have the capability and understanding to select outages that should be included in their Near-term Planning horizion. For those Reliability Coordinators with a significant number of Transmission Planners and Planning Coordinators in their footprint, this requirement change would add a significant burden on the Reliabiltiy Coordinators without benefit to the process. The focus of the Reliabililty Coordinator is in the real-time to one year horizon, Transmisison Planning should be focused on the one year to five year horizon. If there needs to be an entity to oversee and advise the TPL studies conducted by the Transmission Planner it should be the role of the Planning Coordinator.

In addition, these studies are already being performed in the operational arena, therefore there is no benefit in recreating this analysis in the planning horizon. Even if problems were found in the planning horizon, the corrective action(s) would be to forego the outage or to create an op guide. The operational cases have a more accurate near term load/generation profile which are more appropriate for these studies. Recreating these studies in the planning horizon would add no value, but take significant new effort and time to complete.

Likes 0	
Dislikes 0	
Response	
John Babik - JEA - 1,3,5	
Answer	No
Document Name	
Comment	

JEA appreciates the effort of the SDT addressing the directives from the Commission on Order No. 786 issued on Oct. 17, 2013, Paragraph 40. This standard is applicable only to PCs and TPs per the Applicability section, thus RCs are not under any compliance burden. So what course of actions can the PCs and TPs take to show compliance if they do not receive due cooperation/consultation from the RCs? Please see the comment under #5 below as well. The changes add extra burden on the PCs and TPs for compliance on which they have no control.

Additionally, the outage coordination seems to be more of an Operational Planning issue (for next-day studies up to six months) than a Transmission Planning issue (one to ten years studies). No matter how far ahead PCs and TPs study the system, when it comes to the Operation horizon, the outages

need to be studied again with a more realistic system conditions than in the Planning Horizon. Hence any specific analyses performed by PCs and TPs for the outages in the Planning Horizon don't provide much value to the system operators in the Operation horizon. Besides, if the system can't meet the performance requirements due to outages as per R2.1.3 and R2.4.3, the TPs and PCs have no other allowed mitigation plans, such as operational procedures, except to recommend Corrective Action Plans which result in capital improvement projects. Thus planning for outages in the Near-term Transmission Planning Horizon will only result in capital investment that effect the rates of our customers unnecessarily. Instead standard **IRO-017 – Outage Coordination** seems to be a much better place to have this directive from Paragraph 40 of Order No. 786 addressed. **Suggestion**: Keep the existing language of R1.1.2 unchanged from TPL-001-4 and address this in a future revision of IRO-017	
Likes 0	
Dislikes 0	
Response	
larry brusseau - Corn Belt Power Cooperative - 1	
Answer	No
Document Name	Project 2015-10 TPL-001-5 CBPC.docx
Comment	
Corn Belt agrees with the SPP Standards Review Group and its clarification of an important issue regarding the expectations of regulatory staff on the impacts of Requirement 1, Part 1.1.2. The clarification is about the differences in power flow case topologies used by SPP Operations and SPP Planning. Issues found in the operating horizon would be specific to that point in time and would take into consideration any planned outages, forced outages, generation dispatch, transfers, and load levels that would cause concerns. These operating horizon variables would be changing from minute to hour to day to week to month to season to year. The same outage placed in a planning horizon assessment would be placed into a model that has a lot fewer outages, different generation dispatch, different transfer levels, and different load levels. The topology differences between the two power flow models is significant enough that the operation horizon outages would more than likely not cause issues in the Transmission System Planning Performance Requirements (TPL) Assessment. Further, the SPP Standards Review Group states that trying to mimic, follow, or forecast these operating horizon outages in a meaningful manner would be a moving target. This is due to the fact that most of the planned outages are due to maintenance and capital projects that usually do not re-occur within a 3-5 year period, if ever. The SPP Standards Review Group also found the proposed language to be vague and ambiguous, regarding the timeframe, and therefore would be hard to defend during an audit. Corn Belt agrees with the SPP Standards Review Group that the language is unclear as to whether outages should be evaluated only in the season for which they are planned or whether they should be evaluated for the peak or off-peak 1 or 2, and 5 planning horizon. In addition, the reference to the	

number of additional cases and the associated seasons that could be required. Corn Belt agrees with the SPP Standards Review Group suggested proposed language that would tie this process to the TOP Standards instead of the TPL Standards as this is pertaining more to operation related issues.

Also concerned that this could significantly increase the number of near term cases created and studied and add significant work load to tune L&R for these cases. Concern this will significantly increase PC/TP study work load without benefit due to undetermentant amount of outages that need studied. Even though the 6 month duration may not be perfect, it did provide specific criteria to select outages to study. Concern this change will result in significant wasted time and effort to produce results that won't ultimately be used because the same outages will be restudied in ops horizon.

Outages of concern to be studied separately. Base case assumptions.[A1]

Suggested Language:[A2]
R1.1.2 Known critical outage(s) of generation or Transmission Facility(ies) as selected in consultation with the Reliability Coordinator for the Near-Term Planning Horizon for analyses pursuant to Requirement R2, parts 2.1.3 and 2.4.3.

Firmly disagree with the bullet in the Rationale for Requirement R1 Part 1.1.2. "Relying on Category P3 and P6 is not sufficient and does not cover maintenance outages (see P 44);" Category P3 and P6 does sufficiently cover most maintenance outages any utility would expect and the criteria for R1.1.2 should define outages beyond those that are normaly studied as Category P3 and P6.

Futher, the word "limited" in the comment form Question 1 above is not in the proposed language of R1.1.2, and is misleading by implying the intent is for a "small number of" outages. If the intent is for the PC/TP's to study only a limited amount of outages (beyond those already studies as P3 and P6's) then edit the language to state so.

Likes 0	
Dislikes 0	
Response	
Dori Quam - NorthWestern Energy - 1,3 - MRO,WECC	
Answer	No
Document Name	
Comment	

Outage studies — for planned or unplanned outages of any duration — are handled now in the operational horizon with RC coordination. The duration of the outage shouldn't matter. This change would create unnecessary additional work.

Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	No
Document Name	
Comment	

WAPA agrees with the intent to include significant impactful outages that are important to evaluate ahead of what is covered in the Operations Horizon, but we need to ensure that the language change to Requirement 1, Part 1.1.2 supports this intent. It is essential that the scope of outages be limited to significant planned outages that are not hypothetical in nature. Otherwise, there is a concern that this could significantly increase PC/TP study work without an appreciable benefit due to an undeterminant amount of outages that need to be studied. Outage scheduling changes could occur potentially leading to the results from the R1.1.2 analysis becoming irrelevant as it gets closer to when the outage will actually occur (Operations Horizon). These outages will need to be restudied in the Operations Horizon using more accurate information anyway. Even though the 6 month duration may not be perfect, it did provide specific criteria to select outages to study. There is a risk that the proposed language change to R1.1.2 could lead to it being left wide-open regarding what should be included in a Planning model because there are no parameters on what constitutes a significant planned outage.

WAPA disagrees with the bullet in the Rationale for Requirement R1 Part 1.1.2. “Relying on Category P3 and P6 is not sufficient and does not cover maintenance outages (see P 44);” Category P3 and P6 does sufficiently cover most maintenance outages any utility would expect and the criteria for R1.1.2 should define outages beyond those that are normaly studied as Category P3 and P6.

Futher, the word “limited” in the comment form Question 1 above is not in the proposed language of R1.1.2, and is misleading by implying the intent is for a “small number of” outages. If the intent is for the PC/TP’s to study only a limited amount of outages (beyond those already studies as P3 and P6’s) then edit the language to state so.

Suggested Language (add a qualifier to specify these outages should be critical/significant in nature and leave the ultimate decision upon what constitutes a significan planned outage to the PC/TP per R1 that, “shall maintain System models… to complete its Planning Assessment”):

Likes 0	
Dislikes 0	
Response	

Laura Nelson - IDACORP - Idaho Power Company - 1

Answer	No
Document Name	
Comment	

Idaho Power disagrees with the concept to move away from the 6 month outage duration. While it is reasonable to include known outages that will occur in the time horizon being studied, it's unclear how the consultation with the RC will work; in general, the RC is rarely aware of outages 1 to 5 years out unless they are long term (lasting more than 6 months).

Likes 0	
Dislikes 0	
Response	

Angela Gaines - Portland General Electric Co. - 1,3,5,6, Group Name PGE - Group 1

Answer	No
Document Name	
Comment	

PGE agrees in principal to coordinating with the RC when selecting outages to study as part of the TPL assessment. The removal of the 6 Month duration, however, without new language to define the criticality of planned outages to be studied is not recommended. Planned projects require many outages for completion, some as short as a few days and some much longer. The full list of required outages cannot be known in the planning horizon. Without specific criteria for identifying outages, the RC cannot know the criticality without study, creating a paradox. This proposal could potentially require the creation new case for every identified outage, regardless of outage duration, significantly increasing the work required to complete the TPL analysis. It has been PGE’s experience that a single construction outage rarely results in significant impacts to the BES. When several outages overlap, the BES may be affected. It is not possible to know how outages will overlap in the planning horizon. This risk is managed in the Operations Horizon in the NW via the 45 Day Outage Scheduling Process.

The additional requirement to study planned outages in the dynamics analysis section 2.4.3 will be extremely burdensome and not necessary for similar reasons to those stated above.	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
AZPS supports retaining the 6 month threshold as anything less than 6 months may only be a temporary system configuration. The TPL Assessment is a planning assessment and should be limited to standard system configurations. The Operating horizon should address anything occurring in less than 6 months. On a case by case basis outages of shorter duration could be included if mutually agreed upon by the Planning Coordinator (PC)/Transmission Planner (TP) in consultation with their Reliability Coordinators (RCs).	
Likes 0	
Dislikes 0	
Response	
Oliver Burke - Entergy - Entergy Services, Inc. - 1,5	
Answer	No
Document Name	
Comment	

Outage schedules are market-sensitive information. Outages planned for later years often are not posted to OASIS due to the volatility of outage scheduling long in advance of the outage. Putting these outages in models which are then shared with other Transmission Planners risks improperly sharing this market sensitive information outside the OASIS process.

While we recognize the importance of coordinating outage information, long-term planning models are generally outside the timeframe of interest to Reliability Coordinators. Without a compliance requirement to be involved in the process, it is likely that RCs will not give this process the attention it needs to be effective. The requirement to consult with the RC should be either removed, or a requirement should be added for RCs to respond to these consultation requests in a timely fashion.

Transmission Planners need the leeway to model outages appropriately. It is possible to have mutually exclusive outages which can be applied to a model based on the peak or off-beak conditions being modeled. For instance, outages may be scheduled for multiple sections of a line as part of a line reconductoring project. While all of these outages may fall in the same off-peak season, only one of them will be in effect at a time. It is also within the RCs authority to cancel planned outages that degrade the reliability of the system. Developing projects for outages that are optional would not be appropriate unless it was determined that the planned outage was both required and not feasible without reliability challenges deemed to significant to allow by the RC. TPs should be explicitly allowed to select outages based on criteria beyond the scheduling of the outage in order to accurately model the effects of the outage plan.

Likes 0	
Dislikes 0	

Response

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 1,3,5,6

Answer	No
Document Name	

Comment

NIPSCO believes any potential issues associated with planned maintenance outages are best identified through operational studies such as real time, next-day, and seasonal analysis rather than through the annual TPL-001-4 system performance analysis. Planned maintenance outages are almost always of short duration and are commonly scheduled to avoid occurrence during critical peak seasons. Only planned maintenance outages which are reasonably expected to occur during critical peak seasons, such as those six months or longer, should be included in the annual TPL-001-4 system performance analysis.

Removing the existing six month threshold for planned maintenance outages and continually reducing the time of duration requires the analysis of an ever greater number of concurrent generator and line outages beyond any specified in the TPL-001-4 standard including (P2) bus+breaker fault, (P4) stuck breaker, and (P7) common tower. This moves the performance analysis requirements of the TPL-001-4 standard closer to an effective N-2 requirement which was never intended.

Likes 0	
Dislikes 0	

Response

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	

The following answers to all the questions are from our City Light subject matter experts:

Comments: The PCs and TPs are responsible for complying to the TPL-001-4 standard. RCs are under no obligation to comply with same and have no reason to have input on planning horizon outages (more than 1 year out) that are outside the operations planning horizon (less than 1 year out). As indicated in response to question 5, it is agreed that no additional entities should be added to the applicability of this standard, including the RC, who is focused on the operations of the system. A gap in communication between PCs/TPs and RCs may put the PCs/TPs in a position where compliance for this standard are not met.

In the planning horizon, the PC and TP would be the more appropriate entities to be able to identify significant outages. When planning for outages in the near-term planning horizon, considering outages that are longer than 6 months is appropriate. If the 6 month duration is removed, there are too many planned outages that occur regularly that may be identified to be included in the study even when it is not necessary and would be studied in the outage coordination process.

Suggestion: Keep the language in the R1.1.2 of the TPL-001-4 standard.

Likes 0	
Dislikes 0	

Response	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	

The aspects of the current TPL-001-4 and proposed TPL-001-5 standards that address the area of planned maintenance outages mischaracterize the role of transmission planning – which is to provide for an orderly transmission expansion program that ensures the transmission system is adequate, reliable, and resilient at all times in the future given the lead times associated with making necessary system improvements. Adequacy, reliability, and resiliency include the flexibility of a transmission system to allow for the planned outage of any single transmission facility during non-peak periods in a manner that i) does not require the curtailment of firm load and ii) provides for the system to be operated in an N-1 secure state after the single transmission facility has been removed from service for planned maintenance. All transmission facilities require planned outages from time-to-time to facilitate i) maintenance, testing, and/or repair work that cannot be performed hot; ii) to facilitate protection scheme testing, maintenance, and upgrades on facilities with non-redundant protection; iii) to facilitate capital upgrades to the transmission system or other facilities in the vicinity of the transmission facility; or iv) for other purposes. Therefore, the eventual occurrence of a future planned outage on any transmission facility is certain and “known”, not “hypothetical”, only the timing and duration of the future outage could be considered uncertain or “hypothetical”. If the transmission system is not planned in a manner that allows for any single facility to be removed for maintenance under non-peak conditions, then the system will not maintain the necessary adequacy and resiliency to accommodate planned maintenance requirements in general.

In FERC Order 786, the Commission indicated the following at PP 41:

“We agree with commenters such as MISO and ATCLLC that certain elements may be so critical that, when taken out of service for system maintenance or to facilitate a new capital project, a subsequent unplanned outage initiated by a single-event could result in the loss of non-consequential load or may have a detrimental impact to the bulk electric system reliability. A properly planned transmission system should ensure the known, planned removal of facilities (i.e., generation, transmission or protection system facilities) for maintenance purposes without the loss of non-consequential load or detrimental impacts to system reliability such as cascading, voltage instability or uncontrolled islanding.” (emphasis added)

It is “known” that every transmission facility will eventually need to be taken out of service for planned maintenance or other purposes, thus the prudent planning approach to planned maintenance outages should be to ensure that the transmission system is planned with sufficient resiliency to accommodate planned maintenance outages during off-peak periods that will be required regardless of whether or not such activity has been scheduled.

Direction on ensuring the system could me TPL criteria for future potential planned outages was previously given in an interpretation to TPL-002 and TPL-003. Please consider this, as its intent appears to be lost in forming the TPL-001-4 standard.

http://www.nerc.com/docs/standards/sar/MISO_Interpretation_TPL_Revised_20Mar08.pdf

http://www.nerc.com/files/TPL-002-2b.pdf Pg 11

"The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards."*

While some have argued that outages can be fully managed by outage coordination efforts focused on the operating horizon, if the system is not planned and expanded to maintain sufficient adequacy and resiliency to support future outages, the outage coordination functions may be backed into a corner where there is no choice but to shed load to accommodate an outage or deny an outage given the inability of the outage coordination function to make the necessary system upgrades in the operating horizon that should have been made by the planning function within the planning horizon. An important function of planning is to support operations, which includes ensuring the system is adequate and robust enough to provide flexibility to the outage coordination function to schedules planned outages when they are needed without sacrificing reliability or load continuity.

A proposed remedy would be to expand the P3 and P6 contingency definitions to evaluate an additional multiple outage scenario with no load loss. This scenario would include a planned outage, system adjustments, and then a contingency, but no consequential or non-consequential load loss would be allowed for the planned outage element, and no non-consequential load loss would be allowed for the contingent element. This scenario would be evaluated only for non-peak conditions. The idea here is that the system does not need to be planned to support planned maintenance during peak load conditions, since those conditions represent a very small percentage of time. However, under periods where planned maintenance is typically performed (e.g., shoulder peak and light load conditions, etc.), the system should be planned to accommodate the planned outage of any one system element (transmission or generation) while ensuring the system can continue to operate in a manner that is N-1 secure with no non-consequential load loss. This additional aspect of the P3 and P6 contingencies will require an adjustment to the traditional contingency definitions to facilitate service to all loads for the planned maintenance outage element in accordance with how the system would be switched for planned maintenance. For example, the planned maintenance outage of a network transmission line section with tapped distribution substations served by the line would be switch-to-switch (only the section between two adjacent distribution substations that required maintenance would be taken out of service) instead of breaker-to-breaker to ensure all

load could continue to be served during the planned maintenance outage. This change to the standard ensures that there is a minimal level of flexibility to provide for the planned outage of any single element in the system, which better aligns with the overall goal of transmission planning to ensure the system is adequate, resilient, and reliable in the future.	
Likes 0	
Dislikes 0	
Response	
Shawn Abrams - Santee Cooper - 1,3,5,6, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	
Comments: Santee Cooper appreciates the effort of the SDT addressing the directives from the Commission on Order No. 786. This standard is applicable only to Planning Coordinators and Tranmission Planners per the Applicability section and as such the Reliability Coorindators should not be placed under any compliance burden. Adding the Reliability Coordinator adds an extra burden on the PCs and TPs to demonstrate compliance. Order 786 does not require the Reliability Coordinator to be consulted with on outages. The requirement to consult with the Reliability Coordinator should be removed from this standard. Recommend to keep the existing language of R1.1.2 the same as in the current approved version. Outage coordination is studied in the operational planning horizon in accordance with IRO-017 – Outage Coordination. No matter how far ahead PCs and TPs study the system, when it comes to the operational planning horizon, the outages need to be studied again with anticipated system conditions. Any specific analyses performed by PCs and TPs for the outages in the Planning Horizon do not provide much value for Real-time operations.	
Likes 0	
Dislikes 0	
Response	
Darnez Gresham - Berkshire Hathaway - PacifiCorp - 6 - WECC	
Answer	No

Document Name	
Comment	

PacifiCorp agrees that a Transmission Planner in coordination with the Reliability Coordinator should determine which known outages should be studied, but requests the drafting team to provide more clearly defined guidance to both the reliability coordinator and transmission plannner as to the kind of outages that should be considered for this analysis. For example, a known outage of a generator greater than 500 MVA should be studied or a known outage of a transmission element with a facility rating of 800 MVA or higher should be studied. In addition to providing thresholds for outages to be considered, PacifiCorp believes that the drafting team should also consider FERC's option of reducing the duration from 6 months to either 3 or 4 months, otherwise there would be no distinction between momentary outage as simulated per the P3 and P6 event, as compared to a known outage that can change dispatch patterns and expose the system to a reliability issue.

PacifiCorp believes that performing a known outage analysis for year one or year two case provides benefit for both operational and planning horizon, but performing the known outage analysis for a 5 year case does not provide any benefit as the system conditions could have changed significantly and are not known while performing the TPL assessment.

Likes 0	
Dislikes 0	
Response	

David Jendras - Ameren - Ameren Services - 1,3,6

Answer	No
Document Name	
Comment	

We respectfully disagree with several aspects of this proposal. In the first place, we believe that planned/approved outages of significant duration, if any, should be evaluated in the planning horizon for those outages that would occur in the planning horizon. These outages should include any seasonal outages or outages that would last for a majority of the season to be studied. We would agree to let the Planning Coordinators/Transmission Planners decide if the outages would be appropriate to include in the models required for assessement. However, from our perspective, transmission equipment outages are not planned beyond the operating horizon and are not planned for peak-load periods which drive system expansion plans. Daily or weekly outages of transmission equipment for maintenance or construction are planned for off-peak periods, and are typically not approved for beyond the operating horizon. Therefore, the majority of the these outages need not be considered for the planning assessment and should not be a part of TPL-001-5. While it is true that owners of generation equipment plan outages for beyond the operating horizon, these outages for nuclear refueling or regular turbine/generator maintenance are also planned for non-peak load periods. Some transmission maintenance outages are also planned, in the operating horizon, to take advantage of these generation equipment outages to minimize the opportunities for transmission service curtailments. Operations Planning personnel spend hours evaluating transmission system performance considering the various construction and maintenance activities that are proposed to keep the system functioning.   These evaluations are performed in the operating horizon for implementation in the operating horizon, and utilize generation redispatch and transmission system switching as part of operating guides to work around the planned outages while considering the next worst single contingency event. We do not believe that the intent of the corrective action plan is to include temporary operating guides that are needed to facilitate near-term construction and maintenance outages.

Secondly, if the intent of the proposed change is to address maintenance outages, then the requirement for R2 should be changed to specify the need to study maintenance outages during the times that the maintenance outages would be performed. While it is true that P3 and P6 planning events will not cover all maintenance outages plus planning events for beyond N-2 planning, it would cover a significant reliability concern during these off-peak periods.

Thirdly, the Reliability Coordinator (RC) is not an applicable functional entity for this standard. Therefore, we believe that involving the RC in the planning assessment and development of the corrective action plans for long-term system development is inappropriate. The RC has a near-term focus and is often unaware of needed longer-term system developments that are needed to meet TPL-001 planning requirements, as well as local transmission planning criteria. Many of the outages that RCs must address are required for construction or restoration, and likely would not be applicable for future operating conditions.

Likes 0	
Dislikes 0	

Response

Payam Farahbakhsh - Hydro One Networks, Inc. - 1,3

Answer	No
Document Name	

Comment

While we agree with the move away from the 6 month minimum duration outage requirement, we feel strongly that the outages selected by the PC/TP in consultation with their RC should be known outages for the time period beyond Operations Planning time horizon. Required analysis of outages planned in the timeframe within Operations Planning time horizon is addressed in Reliability Standard IRO-017 which are intended to cover the Operations Planning time horizon. Our suggested wording of Requirement 1.1.2 is shown below.

1.1.2. Known outage(s) of generation or Transmission Facility(ies) as selected by the PC/TP in consultation with the Reliability Coordinator for the Near-Term Transmission Planning Horizon beyond Operations Planning time horizon for analyses pursuant to Requirement R2, parts 2.1.3 and 2.4.3.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no ISO-NE, NYISO and NextEra	
Answer	No
Document Name	
Comment	

The new requirement is open ended and may result in Transmission Planners (TP) performing almost a "real time" operations analysis (i.e. what is the impact of this outage / what about that outage) in-lieu of designing the Bulk Electric System (the purpose of TPL-001). NERC IRO-017 *Outage Coordination* was set up for that purpose, and this proposed change would represent a spillover from IRO-017. The TP would be required to develop a Corrective Action Plan for system outages.

The new requirement does not address a scenario where the TP does not agree with the RC regarding what needs to be studied, or how such a disagreement would be managed from the compliance perspective. The "limited known outages" statement in Question 1 is not part of R1.

We recommend the Requirements 1.1.2 and 2.1.3 be revised as follows to clarify which entity has the sole responsibility to select the outages (additions in RED):

R1.1.2 Known outage(s) (for the time period beyond 12-months into the future) of generation or Transmission Facility(ies) as selected by the Transmission Planner or Planning Coordinator following consultation with the Reliability Coordinator for the Near-Term Transmission Planning Horizon for analyses pursuant to Requirement R2, parts 2.1.3 and 2.4.3.

R2.1.3. P1 events in Table 1, as selected by the Transmission Planner or Planning Coordinator following consultation with the Reliability Coordinator, with known outages modeled as specified in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

Alternatively, RC should be removed from these Requirements and TP or PC should have the flexibility to select what needs to be studied; as it relates to outages.

In addition, this new requirement would result in Transmission Planners (TP) or Planning Coordinator performing an annual study as the RC could request a study to review upcoming outages. This could result in a conflict with the existing Requirements that allow the use of past studies to satisfy compliance with TPL-001.

While we agree with the move away from the 6-month minimum duration outage requirement, we feel strongly that the outages selected by the PC/TP in consultation with their RC should be known outages for the time period beyond 12-months from the current date. Required analysis of outages planned in the timeframe of less than 1 year from the current date should be the exclusive responsibility of Operations Planning through reliability standards such as IRO-017 which are intended to cover the Operations Planning time horizon. Our suggested wording of Requirement 1.1.2 is shown below.

Likes 0	
Dislikes 0	

Response

Scott Downey - Peak Reliability - 1

Answer	No
Document Name	

Comment

While Peak agrees that the six month outage threshold should be changed for the reasons described in the rationale provided for proposed requirement R1, part 1.1.2, Peak disagrees with the proposed mechanism of addressing the issues set forth. In accordance with IRO-017-1 requirement R1, the RC is required to have an outage coordination process for transmission and generation outages in its RC Area. This requirement is applicable to the Operations Planning Time Horizon, which is typically considered to be the Time Horizon over which the RC/TOP has assessment responsibility. Outages that are planned further in advance of the Operations Planning timeframe are addressed in the PC/TP's Planning Assessments. These outages are outside the RC/TOP's timeframe of assessment responsibility and are inside the PC/TP's timeframe of assessment responsibility. IRO-017-1 requirement R4, which requires the PC and TP to jointly develop solutions with its respective RC(s) for identified issues or conflicts with planned outages in its Planning Assessment for the Near-Term Transmission Planning Horizon, serves to connect the dots from planning to operations and serves as a valuable hand-off from planning to operations. The requirements in IRO-017-1 were specifically written this way to accomplish the dot-connecting objective.

Regarding outages in the planning horizon, the RC has no knowledge of – or responsibilities for – outages that fall outside the Operations Planning Time Horizon. The proposed requirement as written implies that the RC is to have data for planned outages in the Near Term Transmission Planning Horizon and perhaps even to perform some degree of screening to determine which of those planned outages should be included in the PC/TP's Planning Assessments. This not only results in an additional burden for the RC, but also creates an environment where the RC may have (or be perceived to have) some degree of responsibility for activities that take place outside of its timeframe of responsibility. Accordingly, Peak does not support the proposed approach of having the PC/TP consult with the RC to determine which outages should be included in the PC/TP's Planning Assessments.

By default, proposed requirement R1.1.2 requires the RC to "do something" in order for the TP/PC to be compliant – which in effect is a requirement for the RC. Peak believes this is not a good approach for writing standards. If the RC does not participate in this consultation, or if the consultation is "weak", is the PC/TP faced with a potential compliance ramifications? If such is the case, is the RC subject to any compliance ramifications? Unfortunately, this same issue exists with currently approved IRO-017-1 requirement R4. While such requirements have a good reliability intent, there are better ways of writing requirements to achieve that desired intent. Bottom line, Peak believes there is a better way.

Peak believes that there are alternative solutions that may better address the issues stated in the proposed R1 rationale box.

One approach could be to create a requirement in TPL-001 or IRO-017 for the PC to develop and implement a process for determining the outages to be included in the PC/TP Planning Assessments for the Near-Term Transmission Planning Horizon. The requirement would have no mention of the RC, so as to not create any implied responsibilities for the RC. That said, if a given PC's process happens to include involvement from the RC, and the RC is agreeable to participating, then so be it. However, Peak does not believe that the RC's involvement under the auspices of "consultation" should be stated in a requirement applicable to PC/TPs. There are pros and cons with this approach.

If an objective is to create requirements to better bridge planning with operations and to have the RC provide input to the selection of outages to be included in Planning Assessments, another approach would be modify IRO-017 to create a requirement for the RC to document the criteria that the PC/TPs shall use to determine which planned outages, at a minimum, need to be included in TP/PC Planning Assessments for the Near Term Transmission Planning Horizon. TPL-001 can then have a requirement to include, at a minimum, the outages that meet the RC's criteria. With this approach, the RC's responsibility would stop with defining the criteria for the PCs to use at a minimum. The RC would not be required to consult with PC/TPs beyond that.

Alternately, the TPL-001 standard itself can explicitly specify the criteria for outages that need to be included in the Planning Assessments for the Near Term Transmission Planning Horizon. If an outage of six month duration isn't the right answer, perhaps the standard can find the right answer and include it in the standard rather than getting the RC involved in the decision process.

Additionally, given the high number of PCs and TPs in the Western Interconnection, it is impractical for Peak as an RC to consult with PC/TPs in the determination of outages that should be included in the PC/TP's Planning Assessments. Given this situation, Peak would be in favor of the second or third potential solutions described above.

Likes 0	
Dislikes 0	

Response

Jeffrey Watkins - Berkshire Hathaway - NV Energy - 6 - WECC

Answer	No
Document Name	
Comment	
NVE suggests changing Requirement 1, Part 1.1.2 to known outages selected by the Planning Coodinator/Transmission Planner. The transmission planner should provide justification for the selection of the outages which could include consultation with the RC or other internal processeses.	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
No, Part 1.1.2 should be removed altogether since IRO-017 already cover planned outages in the operations planning and near-term planning horizons.	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	

(1) We are concerned that the proposed changes could require applicable entities to administratively demonstrate communication, coordination, and selection processes for proof of consulting with their RC. This would include a PC-TP selection process that justifies the exclusion of RC-identified outages. The references to Requirement R2 are also cumbersome and require the applicable entity to review other aspects of the standard to determine how to comply with this requirement. (2) We believe the proposed modifications could be simplified to include references to NERC Reliability Standard IRO-017-1, which already requires PCs and TPs to jointly develop solutions for identified conflicts in their Planning Assessments for the Near-Term Transmission Planning Horizon. Near-Term Transmission Planning maintenance schedules identified by TOs and GOs are provided to TOPs and BAs, and then shared with their respective RC, per Reliability Standard IRO-017-1. The RC may have knowledge of future Facility maintenance schedules beyond the Near-Term Transmission Planning Horizon, but only on a voluntary basis as provided by an external entity. We propose this alternative change instead: “Known generation and Transmission Facility outages included in Near-Term Transmission Planning Horizon Planning Assessments for its respective Reliability Coordinator outage coordination process.”	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Duke Energy agrees with FERC and NERC that analysis of transmission and generation outages is a critical function that must be performed with appropriate expertise and knowledge to ensure facility outages of limited duration do not create operational concerns. Duke Energy disagrees that these requirements should be included in a planning related standard (i.e. TPL-001). The related requirements would be more appropriate in an operation related standard (e.g. IRO-017). Duke Energy believes an equally effective and efficient solution to address FERC Order 786 can be obtained by modification of an operationally focused standard. Transmission planners ought to be a resource to assist the work in such a standard, but should not have primary responsibility. Inclusion in the proposed standard of the RC in the “consulting” role of making the determination of what outages must be studied is indicative of the fact that operational considerations are key to proper assessment – from what outage to study under what conditions to what are acceptable actions to take to allow the outage to proceed. Operational personnel have the appropriate mindset, tools and background knowledge to perform the assessment and when necessary, be supported by planning personnel. The TPL-001 standard is intended to ensure sufficient infrastructure is planned to provide the operators a robust enough system to operate reliably under the varying conditions they will experience. It would almost never be	

appropriate to make infrastructure upgrades to alleviate reliability concerns that appear due to outages of limited duration. Transmission planners are expected to evaluate the feasibility of implementation of projects they propose and the outages that will be required as part of developing their TPL-001 corrective action plans. However, the decision to allow outage of any facility for any reason lies with transmission operators. Operating conditions and outage schedules change with time and outage plans must be continuously re-evaluated and revised, up to the very day they are to begin. Conditions change so much that it is not useful nor necessary to study outages throughout the entire Near Term Planning Horizon. The Operating Horizon, usually considered to be 13 months, is a reasonable timeframe for evaluation of proposed outages. Transmission operators are most knowledgable of system transmission and generation outage plans, how they have changed, the interactions between them, the expected system conditions, what are acceptable compensatory actions for reliability concerns…. and have final authority over allowing an outage to take place. Also, performance of the analysis of outages' impact equips transmission operators to be able to make acceptable last minute decisions regarding outages when expected system conditions change, as they often do. It would be inappropriate to expect transmission planners to make those decisions or to rely to a large extent on analysis that transmission planners had performed in the past for maintenance of system reliability in the operating horizon. If the requirement is to remain in the TPL standard it should be modified to make it clear that the RC will determine what outages are to be studied and the period to be studied reduced from the full Near-Term Planning Horizon. Wording in the standard or the technical guidance document should be provided to clarify the RC's role. For example: Outages with a duration greater than 2 months of the same seasonal period or of facilities deemed critical to the operation of the system, in the judgment of the RC, must be evaluated. Such language ensures that the duration of the outage is significant enough to warrant evaluation beyond what will be done under normal operational planning practices. It also allows the RC to exercise their knowledge and expertise when appropriate. The period that evaluation of such outages should be shortened to the first two years of the Near-Term Planning Horizon. Evaluation of outages further into the future than that will likely result in unnecessary studies being performed by the PC/TP due to changes in outage plans. No reliability gap is created because the outages will be studied prior to their execution.	
Likes 0	
Dislikes 0	
Response	
Kayleigh Wilkerson - Lincoln Electric System - 1,3,5,6	
Answer	No
Document Name	
Comment	

Although LES agrees with the move away from the 6 month duration outage, we're concerned that the selection of known planned outages in consultation with the RC unduly complicates the process. Recommend removing the RC from TPL-001-5 in consideration that the TP and PC are already performing these assessments and are capable of making a judgment of including or not including a known planned outage.

Additionally, it is unclear whether R1 is intended to be directed towards the annual MOD-032 model development (e.g., where the PC and TPs jointly develop modeling data requirements), or if the selection of known planned outages is solely part of the Planning Assessment.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	No
Document Name	

Comment

Texas RE appreciates that Standard Drafting Team's (SDT) efforts to develop a flexible and workable Transmission System Planning Performance Requirement Standard. However, Texas RE is concerned that the current proposal does not properly implement the Federal Energy Regulatory Commission's (FERC) directive in Order No. 786 to include planned outages lasting less than six months in some fashion in the planning process and could result in reliability gaps.

In doing so, FERC provided clear guidance that its intent was to expand the number of planned outages required to be including in TPL-001 planning assessments. Specifically, while recognizing NERC has the flexibility in implementing its directive, FERC specifically enumerated several acceptable approaches that all would result in the inclusion of additional planned outages in the planning process. FERC wrote: "we believe that acceptable approaches include eliminating the six-month threshold altogether; decreasing the threshold to few months to include additional significant planned outages; or including parameters on what constitutes a significant planned outage based, for example, on MW or facility ratings." Each of these scenarios share a common trait: the number of planned outages included in required transmission planning analyses will increase.

In contrast with FERC's examples, the proposed TPL-001-5 could result in the inclusion of fewer planned outages in the transmission planning process. In particular, the proposed standard requires only the inclusion of known generation or Transmission outages that are "selected in consultation with the Reliability Coordinator [RC] for the Near-Term Planning Horizon . . ." Under the proposed TPL-001-5, therefore, Transmission Planners (TPs) and Planning Coordinators (PCs) could elect to exclude not only all planned outages with a duration of less than six months, but also additional planned outages with planned durations greater than six months after consultation. While FERC recognized that NERC should retain flexibility in implementing its directive, the current proposal appears to run counter to FERC's intent to ensure that a broader category of planned outages that could result in impacts to the Bulk Electric System (BES) during peak and off-peak periods are examined to ensure they can occur without the loss of inconsequential load or detrimental impacts to system reliability.

The proposed standard revisions further exacerbate this problem by inserting the same "selected in consultation with the [RC]" language into the scope of the annual Planning Assessment requirements set forth in TPL-001-5 R2.1.3. Under the existing TPL-001-4, Qualified Planning studies must include models of the loss of generators, transmission circuits, transformers, shunt devices, and single poles of a DC line. These P1 contingencies must all be modeled to ensure there is no inconsequential loss of load and no interruption of firm transmission service. In contrast, the revised TPL-001-5 permits TPs and PCs to omit P1 contingencies. Specifically, the proposed standard only required including P1 contingency events selected in consultation with the RC. Presumably, the SDT included this language to flow through its proposed modifications to the six-month threshold in TPL-001-5 R1. In doing so, however, the SDT has again broadened the potential modeling exceptions in R2 beyond merely certain planned outages to permit waivers of all P1 contingencies. As such, it is possible that a TP and/or PC may inadvertently fail to study a significant P1 contingency. However, if that event was not identified in the P1 contingency event "selected in consultation with the [RC]", the TP and PC would still have conducted a qualified Planning Assessment. This result is wholly inconsistent with TPL-001's goal of ensuring BES reliability following a wide range of probable contingencies. Texas RE suggests the gap be addressed by the standard requiring that all P1 events are included in the qualifying studies with known outages modeled.

It is also important to note that the "consultation" model envisioned in the proposed standard could lead to a number of other issues. In addition to the problems regarding the inclusion of P1 contingencies, Texas RE points out that in many instances the relevant PC and RC are the same entity. In the ERCOT region, the same entity is responsible for both functions and develops the initial system-wide transmission models. Accordingly, the proposed standard appears to contemplate this entity "consulting with itself." This raises the possibility that planned outages and other P1 events could be unilaterally excluded from the planning process. Further, it would be difficult for Texas RE to address any inadvertent exclusions or omissions in the planning process under the standard as drafted. Again, this does not appear to be the outcome FERC contemplated in issuing its directive.

Texas RE respectfully requests that the SDT reconsider its approach in light of FERC's directive in Order No. 786 and adopt an approach that broadens the scope of planned outages required to be considered in the planning process. At a minimum, Texas RE suggests that if the SDT wishes to retain the "consultation" model, it should explicitly limit its application to planned outages of less than six months and retain the original bright-line requirements for all other scenarios. Under such an approach, the SDT could revise the existing TPL-001-4 R1.1.2 to read: "Known outage(s) of generation or Transmission Facilities with a duration of at least six months or known outages with a duration of less than six months, as selected in consultation with the RC." Texas RE recommends the SDT further revise TPL-001-4 R 2.1.3 to require that annual Planning Assessments model all P1 contingencies currently in the scope of the existing TPL-001-4 Standard, but again permit those models include planned outages lasting less than six months "as selected in consultation with the RC."

Likes 0	
Dislikes 0	

Response

Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	No
Document Name	
Comment	

While the 6 month duration may not be an appropriate requirement, involving the RC is not appropriate either. The responsibility of the RC is “operation” of the system. Any outages in the operating time-frame should have been submitted and reviewed prior to approval. Our expereince in long-term outage planning has shown that it is very unlikely that “planned” transmission outages exist beyond the next six months and that generation outages change weekly. Additionally, to move outages that are expected to last a few weeks to two months into cases that can cover 2-4 months is problematic because as you look at the “most impactful” to include in the base system model, the two or three may not overlap presenting another problem for now selecting what to include. If the Standard stated outages that span the duration of the season being studied that would make this straight forward and remove the RC.

The concept of ***planned outages*** needs to have a footnote or further explanation to clarify that this applies to “planned outages needed to execute the CAP” and be very specific. Maintenance outages should not be addressed in this standard, thus, verbiage should be added to the standard accordingly. Maintenance outage schedules are typically not definitively known beyond 12 months out, and these would be assessed by Operations Planning closer to the desired time of the maintenance outage such that expected system conditions reflected in the study power flow is better known.

If the RC remains included, need to add words to allow the RC’s request to include the exclusion of stability studies of known outages that might impact steady state but clearly don’t impact stability. Examples might be areas of the transmission system that are not electrically close to generation and not in areas susceptible to FIDVR

Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	

The SPP Standards Review Group would like to clarify an important issue regarding the expectations of regulatory staff on the impacts of Requirement 1, Part 1.1.2. The clarification is about the differences in power flow case topologies used by SPP Operations and SPP Planning. Issues found in the operating horizon would be specific to that point in time and would take into consideration any planned outages, forced outages, generation dispatch, transfers, and load levels that would cause concerns. These operating horizon variables would be changing from minute to hour to day to week to month to season to year. The same outage placed in a planning horizon assessment would be placed into a model that has a lot fewer outages, different generation dispatch, different transfer levels, and different load levels. The topology differences between the two power flow models is significant enough that the operation horizon outages would more than likely not cause issues in the Transmission System Planning Performance Requirements (TPL) Assessment. Further, the SPP Standards Review Group would like to state that trying to mimic, follow, or forecast these operating horizon outages in a meaningful manner would be a moving target. This is due to the fact that most of the planned outages are due to maintenance and capital projects that usually do not re-occur within a 3-5 year period, if ever. The SPP Standards Review Group also finds the proposed language to be vague and ambiguous, regarding the timeframe, and therefore would be hard to defend during an audit. The SPP Standards Review Group thinks the language is unclear as to whether outages should be evaluated only in the season for which they are planned or whether they should be evaluated for the peak or off-peak 1 or 2, and 5 planning horizon. In addition, The SPP Standards Review Group have a concern in reference to the number of additional cases and the associated seasons that could be required. The The SPP Standards Review Group would like to suggest proposed language that would tie this process to the TOP Standards instead of the TPL Standards as this is pertaining more to operation related issues.	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Oncor Electric Delivery - 1 - Texas RE	
Answer	No
Document Name	
Comment	
Moving away from the 6 month duration outage to limited known outages mixes clearance coordination studies and daily operational studies with planning studies. This creates planning base cases with outages that may or may not happen. Consultation with the Reliability Coordinator (RC) creates added ambiguity for planning studies.	
Likes 0	

Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	No
Document Name	
Comment	

IID appreciates the effort of the SDT addressing the directives from the Commission on Order No. 786 issued on Oct. 17, 2013, Paragraph 40. This standard is applicable only to PCs and TPs per the Applicability section, thus RCs are not under any compliance burden. So what course of actions can the PCs and TPs take to show compliance if they do not receive due cooperation/consultation from the RCs? Please see the comment under #5 below as well. The changes add extra burden on the PCs and TPs for compliance on which they have no control.

Additionally, the outage coordination seems to be more of an Operational Planning issue (for next-day studies up to six months) than a Transmission Planning issue (one to ten years studies). No matter how far ahead PCs and TPs study the system, when it comes to the Operation horizon, the outages need to be studied again with a more realistic system conditions than in the Planning Horizon. Hence any specific analyses performed by PCs and TPs for the outages in the Planning Horizon don't provide much value to the system operators in the Operation horizon.

Besides, if the system can't meet the performance requirements due to outages as per R2.1.3 and R2.4.3, the TPs and PCs have no other allowed mitigation plans, such as operational procedures, except to recommend Corrective Action Plans which result in capital improvement projects. Thus planning for outages in the Near-term Transmission Planning Horizon will only result in capital investment that effect the rates of our customers unnecessarily.

Instead standard **IRO-017 – Outage Coordination** seems to be a much better place to have this directive from Paragraph 40 of Order No. 786 addressed.

Suggestion: Keep the existing language of R1.1.2 unchanged from TPL-001-4 and address this in a future revision of IRO-017.

Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1 - SERC	

Answer	No
Document Name	
Comment	
It does not make sense to study near-term situation with planning base cases since we would not implement any upgrades. In addition, IRO-017 already contains this requirement.	
Likes 0	
Dislikes 0	
Response	
Joe Tarantino - Sacramento Municipal Utility District - 1,3,4,5,6 - WECC	
Answer	No
Document Name	
Comment	
The existing language is sufficient to ensure long-term outages are considered in the planning process.	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1,5,6, Group Name LCRA Compliance	
Answer	No
Document Name	
Comment	

Requirement 2.1.3 refers to contingency events (specifically P1 events). Section 2.1.4 already requires sensitivity studies associated with the duration and timing of know Transmission outages. Recommend the following wording: "P1 events in Table 1, with known outages modeled as *determined in accordance with* Requirement R1, Part 1.1.2, uner those System peak or Off-Peak conditions."

LCRA TSC supports the changes in 1.1.2 giving flexibility to each region to determine which outages need to be modelled for planning, however, guidance should be provided in the standard not to require that transmission improvements be constructed for transient outage conditions (outages that are due to construction within a single season or of limited duration within a season for instance).

Likes 0	
Dislikes 0	
Response	
Douglas Webb - Great Plains Energy - Kansas City Power and Light Co. - 1,3,5,6 - SPP RE	
Answer	No
Document Name	
Comment	

KCP&L does not support the proposed changes to R1, Part 1.1.2.

The proposed TPL-001 revisions removing the six-month planning time period is without consideration of the expressed scope of TPL-001, to model and study system reliability within the Near-Term Transmission Planning Horizon period which the NERC Glossary defines as 1 to 5 years. Also, the revisions seek to address potential conditions that are better addressed within operational assessments, like TOP-002.

We suggest revisions to R1, Part 1.1.2 not be made.

Expanded Scope

We recognize that the revisions reflect Commission directives but that does not relieve or change our TPL-001 expansion of scope concerns. By removing the six-month modeling threshold, R1 potentially requires modeling that will offer little value in support of BES reliability.

Using planning models to consider contingencies for unusual system conditions is without controversy; however, it is not unusual for issues to appear in real-time system operations that have not been identified in Near-Term planning assessments.

Relevant Variables Not Available for Use in Near-Term and Long-Term Studies

Variables used to develop an accurate study are not available for use in a long-term study: temperature, outages, dispatch, and load and transfer levels. Near-Term planning assessments generally assume some uniform ambient conditions for the area to be assessed. For large RTOs such as Southwest Power Pool, ambient conditions can vary widely across the entire RTO. These system conditions are better assessed in the Operational Planning Horizon.

Of course, Near-Term Transmission Planning Horizon (NTTPH) modeling and actual system operational conditions modeling are both useful; however, unless current operating conditions are considered as part of NTTPH modeling, the modeling does little to protect or improve reliability in the real-time operation of the BES.

Planning Assessment Issue

Proposed TPL-001-5 R1 requires TPs and PCs to maintain system models to perform Planning Assessments; R2 requires completing Planning Assessments. The NERC Glossary defines Planning Assessment as, "Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies."

Real-time operational conditions are not "…future Transmission performance…" and fall outside the purview of TPL-001. Removing the six-month timeframe from R1.1.2 potentially expands consideration of real-time operational conditions. Such an expansion, considering real-time operational variability within NTTPHs, is inconsistent with the "future" language element identified in the defined term, Planning Assessment.

Maintenance Outages Less than Six Months Pose Little Risk to Reliability

The proposed revisions seem to overlook the fact that planned maintenance outages of less than six months in duration pose little or no risk to BES reliability since they are considered as part of the TOP-002 Standards which use planning variables not available at the time NTTPH studies are completed. Additionally, many planned outages can be taken at times of opportunity when their impact on system operations is reduced.

Examples in Support of Position

Finally, we offer a couple of examples that further support our position: that the proposed revisions to TPL-001 R1.1.2 are already, and more effectively, addressed by real-time operational studies, using variables not available at the time NTTHP studies are completed.

Example 1

In a long range planning study/assessment there might be an exceedance identified for a maintenance outage. Normally, mitigation of that exceedance takes place during near term/real time operational studies. Maintenance outages are impacted/affected more by real-time operational conditions, not some future set of assumed conditions.

Example 2

In the case of outage caused exceedances; they are temporary and typically resolved using operating guides. Also, a Long-Term Transmission Planning Horizon study or a NTTPH study have little value addressing outage caused exceedances which are better addressed when considered closer to the time of the event, allowing the study to consider conditions likely most similar to those at the time of occurrence.	
Likes 0	
Dislikes 0	
Response	
Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC ("CenterPoint Energy") disagrees with the proposed changes. CenterPoint Energy recommends replacing the proposed language for Requirement 1, Part 1.1.2 with "Outage(s) of generation or Transmission Facility(ies) with a duration of at least six months in the Near-Term Transmission Planning Horizon." CenterPoint Energy's recommendation is based on the following: • Moving away from the six month duration outage goes beyond the intent the Planning Assessment of NERC Standard TPL-001-4. Planned outages less than six months should be evaluated in the Operations Planning time horizon. • Per NERC Standard IRO-017-1 Outage Coordination, coordination is already required between several applicable entities, including the Reliability Coordinator, Planning Coordinator, and Transmission Planner, before any planned outages are included in the Near-Term Transmission Planning Horizon.	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1,3,5,6, Group Name AECI & Member G&Ts	
Answer	No

Document Name	
Comment	
Removing the 6 month duration moves the TPL assessment from the near term planning horizon to the operational planning horizon. Remove “in consultation with their Reliability Coordinators”. This change will deluge the RCs with requests. The decision on what outages to include should rest with the PCs and TPs who may want to consult their RC, but might also want to consult neighboring PCs and TPs as well.	
Likes 0	
Dislikes 0	
Response	
Michael Haff - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	No
Document Name	
Comment	
The revisions to R1.1.2 and R2.1.3 require the individual PCs and TPs to contact the RC to discuss known outages for long term planning purposes. Seminole is concerned that meeting with the individual TPs and PCs for long term planning of outages is not a function of the RC, and that the drafting team should seriously reconsider the additional requirements it is now placing on the RC, especially since planned outages are already coordinated within the Operations Planning horizon. Additionally, Seminole believes that this requirement should be placed within the existing IRO-017 standard if there is a true reliability need for such coordination; TPL-001-5 is not the correct location for this type of coordination. In R1.1.2, if the RC believes an outage should be included in the System Model and the TP and PC do not believe the outage should be included, what is the process for remedying this problem? Do the TP and PC merely have to show that they consulted with the RC, not necessarily that they came to agreement?	
Likes 0	
Dislikes 0	
Response	
Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	

Answer	No
Document Name	

Comment

No, there are a few concerns introduced by the proposed modification of part 1.1.2:

· Moving from a firm threshold to consultation creates ambiguity and potential reliability gaps, and is not an effective means to address the FERC concerns expressed in Order 786. when there are no criteria as to how that consultation is to proceed. Further, we do not read FERC's directive on P.40 of Order 786 to mean replacing the 6-month planned outages with other approaches. Rather, we interpret that directive to mean modifying the TPL-001 standard to address the potential impacts of excluding planned outages of less than 6 months in planning assessments.

· Replacing the 6-month threshold with a consultation with the RC has the following potential shortfalls:

a. The TP's/PC's footprint is not necessarily the same as the RC's; there can be several RCs within a TP/PC area, or the other way around. In these cases, who should be consulted and how to reach an agreement if multiple entities are involved? And on what basis should the RC(s) recommend inclusion of certain planned outages?

b. While the draft standard places an obligation on the TP/PC to consult, there is no mirror obligation on the RC to respond. What if the RC does not respond? Is the TP/PC held non-compliant for having no planned outages included in the planning assessment?

c. Two entities may be assessing the same system conditions included the planned outages, but they could come up with quite different assessment results due to different risk tolerances or approaches applied in the assessment. If the TP/PC and the RC, or multiple RCs when more than one is involved, come up with different assessment results, whose results should prevail?

To address the FERC directive without the above potential reliability gaps or shortfalls, we offer the following suggestions:

1. Keep the 6-month planned outage threshold, and supplement it with: Any planned outages that are deemed by the Reliability Coordinator of the concerned facilities to have a reliability impact in the tome frame of the planning assessment being pursued by the Transmission Planner or Planning Coordinator.

2. Add a requirement for the RC to respond to the TP's/PC's request to assess the reliability impacts of planned outages of less than 6 months during the assessment period.

Note: CAISO and ERCOT do not support this comment.

Likes 0	
Dislikes 0	

Response	
Gary Trent - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	No
Document Name	
Comment	
Due to the large number of Planning Coordinators and Transmission Planners in the Reliability Coordinator area, this would be too much of a burden on the RCs to provide appropriate feedback without causing a significant delay or setting the threshhold too low where most if not all planned outages which would significantly increase the time needed to complete the assessment. If the 6 month requirement is removed, the PCs/TPs should provide a reason those planned outages were selected. This would be similar to the language allowing the PCs/TPs to determine which Planning Events are selected to evaluate.	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Florida Municipal Power Agency - 3,4,5 - FRCC	
Answer	No
Document Name	
Comment	
FMPA appreciates the efforts put forth by the SDT to address the Commission directives from Order No. 754 and Order No. 786. We agree with R1 Part 1.1.2 and subsequently with R2.1.3 (steady state analysis). The concern here is that steady state events refer to coordinating with the RC while stability events do not – the implication being that in stability we must study all known outages as opposed to those which are carefully selected. Also, for 2.4.3, explicitly calling out P1 events from Table 1 effectively removes the ability of the PC and TP to apply engineering judgement to study those events that are expected to produce the most significant impacts, and instead adds “busy work”. Furthermore, the extent of that “busy work” is unclear, since if we are required to run P1 events, how many buses away from the affected area must we simulate these? Few P1 events are simulated in stability studies because P2 events at the same buses are almost always more severe. Please see our comments in the General Comment section below.	

Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	

We disagree with the fundamental premise that there is a reliability need/benefit of studying scheduled transmission outages in the Near-Term Planning Horizon –whether or not they are identified in consultation with the Reliability Coordinator (RC). This is because:

1. scheduled transmission outages almost always qualify as “known” outages only when they are approved/granted by the RC;

2. transition from “prospective” to “known” outages almost always occurs within the operations horizon (0 to 13 months), and

3. very few, if any, transmission outages are approved/granted by the RC well in advance to become “known” outages in the Near-Term Planning Horizon.

Consequently, we assert that deleting Part 1.1.2 from the standard will not have any adverse impact on the planning assessment of future BES reliability.

However, if the SDT is not persuaded to delete Part 1.1.2, we recommend improvements to the verbiage in Part 1.1.2 to address the ambiguity and lack of detail associated with what comprises “consultation with the Reliability Coordinator”.

Further, it is also ounclear why scheduled outages that are “known” would nevertheless have to be “selected” in consultation with the RC – wouldn’t *all* outages that are scheduled/approved by the RC for Year One through year 5 time horizon qualify as “known” outages to be included in the analyses (and hence no selection)?

NERC should provide a clear directive to the RC, where the RC provides a list (in a timely manner to complete the assessment) of know outages to the TP, only after the RC coordinates with the TO for transmission outages and with the GO for generation outages. The TP/PC do not own any assets nor are they aware of predetermined maintenance schedules required by both the TO and GO. Additionally, if TOs, GOs, etc. actively participate as required by MOD-032-1, these known outages would be captured for the respective seasonal time frame.

We suggest the SDT looks at the recommendations in NERC SAMS white-paper on Order 786 for guidance in the case that 1.1.2 is revised.	
Likes 0	
Dislikes 0	
Response	
Long Duong - Public Utility District No. 1 of Snohomish County - 1,4,5	
Answer	No
Document Name	
Comment	
Obtaining known outage(s) or Transmission Facility(ies) through the RC for the Near-Term Planning Horizon may be difficult for PCs and TPs, unless the RC has a maintained and approved list of known outages for TPL studies. To sort out applicable outages for the Operations and Planning studies would be a burden for the RC. Additionally, the expectation for the PC/TP to read and extract that information from the RC's maintained and approved list of known outages, is impractical. Therefore, SNPD suggests the Drafting Team remove any language that requires consultation with the RC and we recommend restoring the original language to Requirements 1.1.2 and 2.1.3 and restating "Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months." If/when the Drafting Team prefers to have a lesser duration than six months, as required by NERC staff, we would support a duration of at least 3 months, for "Known outage(s) of generation or Transmission Facility(ies) with a duration of at least three months."	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

The proposed coordination of outages with the RC forces a merging of two disconnected timeframes, and reduces the RC's focus on operational activities. The prescribed 6-month outage duration in the current standard provides a clear separation between the Operations Planning Horizon and the Near-Term Planning Horizon. Furthermore, asking the RC to be directly involved in the near term planning horizon expands on their defined purpose as documented in the NERC Rules of Procedure. It is unclear what types of outages are to be considered under 1.1.2. SRP recommends clarification on what types should be considered e.g. breakers, switches, etc. It is unclear what "consultation" means. If the SDT retains the proposed changes, SRP recommends the SDT clarify what level of coordination is required.	
Likes 0	
Dislikes 0	
Response	
faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	

The NSRF recognizes the TPL drafting team is attempting to address a directive from FERC Order 786 in a reasonable and flexible manner. It's the NSRF's understanding that FERC expressed concerns about maintenance outages of equipment that could not be taken out-of-service even at low load levels. The NSRF agrees if there are known or demonstrated important BES generators, lines, transformers, or bus sections that cannot be taken out-of-service even at Off peak load levels, a Corrective Action Plan (CAP) seems apprpriate. The RC or TP could list the known or demonstrated Element on a corrective actions list for the TPL standards similar to PRC-023 and R6. Any newly identified Protection System should have a similar study and implementation period clearly outlined in the standard if possible. There are concerns that Reliability Coordinators do not have (1) an adequate venue for consultation on selecting outages and (2) knowledge of outages with sufficient lead time (36 or 60 months advanced knowledge) to perform the required assessments and implement resulting Corrective Action Plans.	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Since RC is now required to supply planned outage information they should become an applicable entity.	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1	
Answer	Yes

Document Name	
Comment	
ATC agrees with the proposed change, but is concerned that Reliability Coordinators do not have (1) an adequate venue for consultation on selecting outages and (2) knowledge of outages with sufficient lead time (36 or 60 months advanced knowledge) to perform the required assessments and implement resulting Corrective Action Plans.	
Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2 - NPCC	
Answer	Yes
Document Name	
Comment	
ISO-NE encourages conforming changes to Reliability Standard IRO-017.	
Likes 0	
Dislikes 0	
Response	
Jameson Thornton - Pacific Gas and Electric Company - 1 - WECC	
Answer	Yes
Document Name	
Comment	

Additional guidance on “consultation” with the RC would be helpful, should this point to IRO-17?. In addition to this the SDT should consider adding the RC to the applicable entities.	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Aubrey Short - FirstEnergy - FirstEnergy Corporation - 1,3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hasan Matin - United Illuminating Co. - 1,3 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shelby Wade - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC,RF, Group Name PPL - Louisville Gas and Electric Co.	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Deborah VanDeventer - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell – Tacoma Public Utilities (Tacoma, WA) - 3	

Answer	No
Document Name	
Comment	
1. IRO-017-1 already requires the RC to maintain a coordination process for the Near-Term Transmission Planning Horizon. The proposed approach in TPL provides little guidance to the RC/TP/PC as to what level of detail to model future outages. This may lead to widely varying practices across regions. 2. We support the other approaches suggested by FERC to limit the scope based on both time and outage significance. The proposed alternate for R1.1.2 is: Schedule outage(s) of Generation or Transmission Facility(ies) that are identified by the Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and lasting longer than 90 days. 3. It is important to note the difference between a planned outage in the sense: (1) that maintenance crews “plan” for insulation testing of every transformer every three years, and (2) that a nuclear plant plans to be offline for refueling from exactly 3/3/2019 @ 19:30 to 9/15/2019 08:00. In the former case, the exact outage dates are both unknown and highly flexible, whereas with the latter the outage has specific dates that can be modeled and it must occur regardless of system conditions. The previous 6 month limit served as a screen to identify only those outages which were likely to occur during critical system conditions. Most maintenance is scheduled to avoid system peaks. 4. It unclear how to model planned outages in year one, year three or year four if the TPL planning assessment uses year two and year five.	
Likes 0	
Dislikes 0	
Response	

2. Do you agree with the proposed changes to Requirement 2, Part 2.4.5 which addresses the Federal Energy Regulatory Commission (FERC) order to add the spare equipment with long lead time to the dynamics analysis?	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
We do not see any reliability gap in the existing standard TPL-001-4 due to the absence of Part 2.4.5. This is because, based on our operating experience, the unavailability of long lead time spare equipment (typically auto-transformer and shunt reactor) has rarely, perhaps never, resulted in unacceptable stability outcome. That is, the risk for instability in BES due to unavailability of spare equipment is minimal, if not negligible. And any BES vulnerabilty to unacceptable stability performance will get adequately assessed when performing stability analyses for P3-P6 Planning Events. Consequently, there is minimal, perhaps even negligible, incremental benefit to be realized by performing additional stability analyses for P1 and P2 events by using prior facility outage as the proxy for unavailability of long lead time equipment failures. Therefore, we do not support the addition of Part 2.4.5 in the draft TPL-001-5 standard.	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Florida Municipal Power Agency - 3,4,5 - FRCC	
Answer	No
Document Name	
Comment	
Similar to the comments entered for question 1 above, explicitly requiring that P1 events be simulated now removes the ability to apply engineering judgment. P1 events would not normally be studied in stability since P2 events at the same buses would produce more severe impacts. In addition, explicitly	

calling out items from Table 1 introduces the ambiguity of how many locations must be studied, since in stability, unlike steady state, it is not feasible to study events at every bus in the system. Please see our comments in the General Comment section below.	
Likes 0	
Dislikes 0	
Response	
Gary Trent - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	No
Document Name	
Comment	
The outage of a piece of equipment with a long lead time should be considered under P6 conditions and not have any additional requirements.	
Likes 0	
Dislikes 0	
Response	
Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	
Answer	No
Document Name	
Comment	
The word "studied" should be changed to "assessed" or "evaluated" (and the same change should be made in Part 2.1.5.) Overall though, we're more interested in the change for 2.4.5 since not all equipment that's part of a spare equipment strategy would require stability simulations (e.g. a reactor), whereas steady state analysis is more commonly applicable	

Note: ERCOT does not support this comment.	
Likes 0	
Dislikes 0	
Response	
Michael Haff - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	No
Document Name	
Comment	
Seminole endorses the comments submitted on this Project by JEA.	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1,3,5,6, Group Name AECI & Member G&Ts	
Answer	No
Document Name	
Comment	
If FERC requires the standard to address spare equipment for dynamics, there should be language that makes it clear that if the non-spared equipment is far away from where the dynamics contingencies are being simulated (i.e. generating stations) then it does not need to be considered. Dynamics contingencies aren't run system-wide like loadflow.	
Likes 0	
Dislikes 0	

Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	No
Document Name	
Comment	
The possible unavailability of long lead time equipment can result in the thermal or voltage planning criteria violations but not on the transient stability of the BES. Hence adding this requirement will burden the PCs and TPs with extra work with no significant improvement in the reliability of BES. Suggestion: Requirement 2, Part 2.4.5 is not needed.	
Likes 0	
Dislikes 0	

Response	
Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Need some verbiage to allow for the exclusion of studies of unavailable equipment that might impact steady state but clearly don't impact stability. Examples might be areas of the transmission system that are not electrically close to generation and not in an area susceptible to FIDVR. An extra sentence "Detailed stability assessments are required only for scenarios where a stability impact could be possible as a result the unavailable equipment" or something simiiar would be appropriate.	
Likes 0	
Dislikes 0	

Response	
Jameson Thornton - Pacific Gas and Electric Company - 1 - WECC	
Answer	No
Document Name	
Comment	
PG&E agrees with the addition of part 2.4.5, however we believe that more details and clarification on the selection of the transmission equipment, and P1 and P2 contingencies is needed. It is recommended to add language that defines what “major Transmission equipment” would require a stability study. We also offer the the following change to the selection of the P1 and P2 categories from Table 1: “…The studies shall be performed for the P1 and P2 categories identified in Table 1 **[that are expected to produce more severe System impacts on its portion of the BES],** with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.”	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT recommends removing P1 events from Part 2.4.5. The current TPL-001-4 standard already requires entities to evaluate P6 events, which produce the same contingency results that studying P1 events would produce assuming unavailability of long-lead time equipment. It is unnecessary to require the proposed analysis in Part 2.4.5.	
Likes 0	
Dislikes 0	

Response	
Jeffrey Watkins - Berkshire Hathaway - NV Energy - 6 - WECC	
Answer	No
Document Name	
Comment	
NVE is concerned that the scope of this requirement is infeasible. Depending on the amount of spare equipment available, to add dynamic analysis for P1 and P2 events for each unavailable spare, could result in a large number of contingency cases to run. Depending on the number of cases to run, there could be significant resource or run-time issues. As a specific example, it takes approximately 3 weeks for NVE to compute (run) stability analysis on a single model. For 20 pieces of BES equipment without spares, it would push the run-time for all P1 and P2 events to far beyond 1 year, not including time for analysis of the results by staff. NVE recommends allowing the transmission planner to select which P1 and P2 events should be run for each unavailable spare, rather than all P1 and P2 events.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no ISO-NE, NYISO and NextEra	
Answer	No
Document Name	
Comment	
We recommend replacing the word “studied” with “assessed”. Not all major Transmission equipment that may become unavailable due to an entity’s spare equipment strategy may require stability analysis (e.g. the unavailability of a reactor), and thus studies may not be required in all cases.	
Likes 0	

Dislikes 0	
Response	
Shawn Abrams - Santee Cooper - 1,3,5,6, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	
Comments: The unavailability of long lead time equipment can result in the thermal or voltage planning criteria violations but not necessarily on the transient stability of the BES. Hence adding this requirement will burden the PCs and TPs with extra work with no significant improvement in the reliability of BES. Recommend removing this requirement.	
Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2 - NPCC	
Answer	No
Document Name	
Comment	
The word “studied” should be changed to “assessed” or “evaluated” [and the same change should be made in Part 2.1.5.]	
Likes 0	
Dislikes 0	
Response	

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	

Steady state analysis per sub-requirement 2.1.5 of the TPL-001-4 standard should be able to capture any thermal or voltage concerns when spare equipment is unavailable due to long lead time. Revising the sub-requirement 2.4.5 to include stability analysis to unavailable equipment due to long lead time potentially adds significant workload without adding any more value than the results of steady state analysis.

Suggestion: Retain the existing language in sub-requirement 2.4.5 of the TPL-001-4 standard.

Likes 0	
Dislikes 0	
Response	

John Babik - JEA - 1,3,5	
Answer	No
Document Name	
Comment	

The possible unavailability of long lead time equipment can result in the thermal or voltage planning criteria violations but not on the transient stability of the BES. Hence adding this requirement will burden the PCs and TPs with extra work with no significant improvement in the reliability of BES.

Suggestion: Requirement 2, Part 2.4.5 is not needed.

Likes 0	
Dislikes 0	
Response	

Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	No
Document Name	
Comment	
Agree with the concept but the word “studied” may have unintended consequences. The words “assessed” or “evaluated” are more appropriate in that devices that do not impact dynamics and therefore may not require a “study” to evaluate the dynamic impact.	
Likes 0	
Dislikes 0	
Response	
Jeff Powell - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
TVA does not see any significant benefit of including the unavailability of long lead time equipment in the dynamic analysis. Potential issues would already be identified sufficiently in dynamics P6 events. If there is an outage of long lead time equipment, operations would mitigate around any potential issues by creating an op guide or utilizing another mitigating measure.	
Likes 0	
Dislikes 0	
Response	
Bridget Silvia - Sempra - San Diego Gas and Electric - 1,3,5	

Answer	No
Document Name	
Comment	
Order No. 786 does not appear to order, or direct NERC, to change TPL-001 to include stability analysis as part of the spare equipment strategy assessment [see page 58 of Order No. 786]. FERC directed "…NERC to consider a similar spare equipment strategy [as steady state] for stability analysis". SDG&E agrees with NERC's original comments found in Order No. 786 that additional stability assessment will not yield meaningful information and provide a significant reliability benefit. SDG&E recommends removal of section 2.4.5.	
Likes 0	
Dislikes 0	
Response	
Robert Ganley - Long Island Power Authority - 1	
Answer	No
Document Name	
Comment	
Logically, this modification makes sense. However, in practice, this modified requirement is somewhat redundant with Table 1, P3 and P6 events. P3 and P6 events are applicable for stability analysis. The additional study burden may not be commensurate with the expected incremental reliability benefit. For stability analysis covering P3 and P6 events, the initial event (i.e. element or facility outage) is carefully selected to be a impactful outage. In practice, existing study procedures related to P3 and P6 events are a good proxy for the assessment of unavailability of long lead time equipment. We would encourage the SDT to inquire about existing study practices for P3 and P6 events (from the REs and the ISO's) to assess if those existing study practices satisfy the intent of the proposed Req # 2.4.5.	
Likes 0	
Dislikes 0	
Response	

Douglas Webb - Great Plains Energy - Kansas City Power and Light Co. - 1,3,5,6 - SPP RE	
Answer	Yes
Document Name	
Comment	
KCP&L agrees with the proposed changes to R2, Part 2.4.5.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
The SPP Standards Review Group agrees with drafting team adding the new sub-part of Requirement R2 to address the spare equipment issue in the stability assessment. The SPP Standards Review Group would like the regulatory bodies to consider adding language in the Steady-State Assessment area of NERC Standard TPL-001 to address the Stability Assessment of the spare equipment strategy. This would mean that if a spare equipment strategy caused issues in the Steady State Assessment, it would prompt the Transmission Planner (TP) and Planning Coordinator (PC) to perform additional Stability Assessments for those specific issues.	
Likes 0	
Dislikes 0	
Response	

Kayleigh Wilkerson - Lincoln Electric System - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Requirement R2.4.5 specifies that studies be performed for the P1 and P2 categories; whereas, Requirement R4 specifies that R2, Parts 2.4 and 2.5, be performed based on the Contingency analyses listed in Table 1. To improve clarity, LES recommends rewording R4 as follows: R4. “For the Stability portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons as described in Requirement R2, Parts 2.4 and 2.5.	
Likes 0	
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Peak supports the idea behind the requirement, as it could flag important reliability issues that operations planners need to be aware of.	
Likes 0	
Dislikes 0	
Response	
Payam Farahbakhsh - Hydro One Networks, Inc. - 1,3	

Answer	Yes
Document Name	
Comment	
We recommend replacing the word “studied” with “assessed”. Not all Transmission equipment that may become unavailable due to an entity’s spare equipment strategy may require stability analysis (e.g. the unavailability of a reactor), and thus studies may not be required in all cases.	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 1,3,6	
Answer	Yes
Document Name	
Comment	
System adjustments would be required following the outage of the equipment with long lead times. Such adjustments should include generation redispatch to address both steady-state and stability concerns. Reviewing system stability issues including system adjustments following the long-term outage of critical system equipment is a reasonable enhancement.	
Likes 0	
Dislikes 0	
Response	
Angela Gaines - Portland General Electric Co. - 1,3,5,6, Group Name PGE - Group 1	
Answer	Yes
Document Name	

Comment	
PGE agrees that the dynamics analysis include spare equipment with long lead times. The requirement will add a limited number of additional cases to be studied. This will increase the time required to complete the dynamics analysis, and therefore increase costs to PGE to demonstrate compliance with this standard.	
Likes 0	
Dislikes 0	
Response	
larry brusseau - Corn Belt Power Cooperative - 1	
Answer	Yes
Document Name	
Comment	
Corn Belt agrees, but suggests that “more than 1 year” be substituted for long lead time throughout TPL-001-5 where appropriate for better clarity. Concerns that the number of additional dynamic analyses to include long lead time items taking more than 1 year for P1 and P2 needs to be bounded. There are real computational constraints that could take months to run. An example could give the Transmission Planner discretion to chose the worst conditions.	
Likes 0	
Dislikes 0	
Response	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	Yes
Document Name	

Comment	
The NSRF agrees, but suggests that “more than 1 year” be substituted for long lead time throughout TPL-001-5 where appropriate for better clarity. The NSRF has concerns that the number of additional dynamic analyses to include long lead time items taking more than 1 year for P1 and P2 needs to be bounded. There are real computational constraints that could take months to run. An example could give the Transmission Planner discretion to chose the worst conditions.	
Likes 0	
Dislikes 0	
Response	

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Long Duong - Public Utility District No. 1 of Snohomish County - 1,4,5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1,5,6, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe Tarantino - Sacramento Municipal Utility District - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1 - SERC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Darnez Gresham - Berkshire Hathaway - PacifiCorp - 6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Oliver Burke - Entergy - Entergy Services, Inc. - 1,5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response
Deborah VanDeventer - Edison International - Southern California Edison Company - 1,3,5,6 - WECC

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response
Laura Nelson - IDACORP - Idaho Power Company - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dori Quam - NorthWestern Energy - 1,3 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shelby Wade - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC,RF, Group Name PPL - Louisville Gas and Electric Co.	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hasan Matin - United Illuminating Co. - 1,3 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 1,3,4	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

John Merrell – Tacoma Public Utilities (Tacoma, WA) - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

3. Do you agree with the further clarification of relay to components of a Protection System with the additional footnote to clarify P5 and extreme events?	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
While the revised footnote is an improvement, clarifications are still needed to properly identify the redundancy requirements. We believe that minimum design requirements should be included in the standard. That will allow the Planning Coordinators/Transmission Planners to have a consistent interpretation of the footnote 13. The following questions demonstrate the ambiguity around redundancy: - Is it allowed to have two control circuitries that use different wires but share the same control cable? - Do the trip coils need to be monitored? There are situations when non BES elements are connected to BES buses (e.g. radial circuits supplying loads). The standard must clarify which protection systems failures needs to be studied since an uncleared close in fault on a non BES element connected to a BES bus has the same consequence as an uncleared close in fault on a BES element. Do the protection systems installed on non BES elements connected to BES buses and protecting portions of the BES buses need to meet redundancy criteria?	
Likes 0	
Dislikes 0	
Response	
Robert Ganley - Long Island Power Authority - 1	

Answer	No
Document Name	

Comment
General recommendation: Footnote 13 should be carefully reviewed and modified (or expanded), as necessary, to be consistent with the Rationale for the modified P5 event, and also consistent with the NERC Glossary definition of “Protection System”. Enough detail should be provided in the footnote to ensure clarity of what needs to be considered. Footnote 13.1 mentions “A single protective relay”. As written, this does not provide sufficient detail for the planner or protection engineer to focus on. The term protective relay needs to be clarified. For example, could this include auxiliary relays such as lock-out relays that are used for tripping (function 86)? Alternatively, does this non-capitalized term only apply to relays that operate on or respond to measured electrical quantities such as current and voltage? Additional clarification is required to allow the planner / protection engineer to be completely focused on what is required for compliance. The rationale mentions that the scope of consideration should be limited “to those relays that are used for primary protection at the local terminal…”. What is meant by “primary protection”? Footnote 13.4 needs clarification. For example: - Does 13.4 mean that redundant relays tripping through a single wire to a single trip coil would constitute a non-redundant component of a Protection System? - Does 13.4 mean that redundant relays tripping through a single trip coil would constitute a non-redundant component of a Protection System? Considering the complexities of 13.4, sample, or representative protection system diagrams that would constitute examples of non-redundant components of a Protection System would be helpful. Such diagram(s) would provide clarity in a similar fashion as the diagrams provided in the NERC BES Reference Document. A general concern here is that this modified footnote, as written, is very confusing. The confusion imposed, along with the additional study burden, may not be commensurate with the expected incremental reliability benefit. Finally, we would note for consideration, that failure of a non-redundant component of a Protection System could result in not only increased total fault clearing time, but also an increase in the number of elements that must be tripped to clear the fault. It is recommended that the Rationale section be modified to mention this additional reliability implication.

Likes 0	
Dislikes 0	

Response	
Quintin Lee - Eversource Energy - 1,3,5	
Answer	No
Document Name	
Comment	

We disagree with the inclusion of the communication system component to Table 1 footnote 13. A single point of failure in a communication system component poses a lower risk for delayed clearing for a variety of reasons and should not be included in footnote 13 as stated by the NERC SPCS/SAMS Order 754 report. Analyzing these risks in planning studies provides significant additional burden for limited gain in reliability.

We understand the SDT's reasoning but urge them to reconsider as this will add a whole new level of detailed analysis by the entities which will lead to a lot of questions requiring guidance from the SDT to ensure consistent application continent-wide.

Basis for our position

To effectively analyze a single point of failure (SPOF) in communication systems the protection schemes used to protect the element and operation of these schemes need to be considered. Looking merely at common hardware, common circuitry and a common communication path is not enough to determine if a single point of failure exists. For example a common communication path can be used for both System A protection via a Directional Comparison Blocking Scheme (DCB) and System B protection via Line Current Differential. If the common communication path fails and a fault then occurs, the DCB scheme will trip with no intentional delay and clear the fault (proper communication system function is not needed). DCB misoperation (overtrip) is associated with faults outside the zone of protection and thus is not associated with delayed clearing as specified in Table 1. Eversource would contend that this is not a single point of failure. Does the Drafting team and the rest of NERC agree?

If communication systems are to be included in footnote 13, considerable additional guidance will need to be included in the standard to ensure only the correct consistent application of SPOF continent-wide. The proposed footnote 13.2 states "A single communications system, necessary for correct operation of protective functions, which is not monitored or not reported."

{C}· What does "not monitored or not reported" mean? If an entity performs a manual carrier check-back test once every 4 months, which is allowed for unmonitored protections system communication system component maintenance per PRC-005, is that considered monitoring or is that "reporting" for the purposes of this standard? Most carrier systems utilize automatic check-back functionality in which case the communication path and end enquipment is checked once a day. Is that frequent enough to be considered "monitored"? PRC-005 uses the following definition for a monitored communication system: "Any communications system with continuous monitoring or periodic automated testing for the presence of the channel function, and alarming for loss of function". Alarming criteria in PRC-005 is specified as : "Alarms are reported within 24 hours of detection to a location where corrective action can be initiated."

{C}·	Is having System A and System B protection communication paths share a common structure a single point of failure, such as a common microwave tower? NPCC Directory 4 does not count this as a recognized single point of failure.

{C}·	Is having System A and System B protection communication paths utilize third party leased communication path a common point of failure even if the third party claims they are diverse (two leased phone lines). NPCC Directory 4 would discourage this and claim that it is not an effective diverse path.

We agree that today, most entities do enable continuous or periodic automated testing of their communications system components and do alarm them to a 24/7 montiored control center where action can be taken. Therefore, we feel the effort to correctly defined and identify the small number of unmonitored communication systems that correctly meet the SDT intent, as it applies to delayed fault clearing, is overly burdensome relative to the reliability benefits.

Likes 0	
Dislikes 0	

Response

Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF

Answer	No
Document Name	

Comment

No. The NSRF recommends that “Cascading” be replaced with a specific MW number such as the loss of 2,000 MW of generation as referenced in the EOP-004 standard. The term “Cascading” remains too vague and subject to change. A MW threshold is a better “bright line” criteria.

The NSRF recommends each BES Protection System component class be covered explicitly in Footnote 13 along with an inclusion or exclusion justification. Abrief Protection System scope for Footnote 13 may also be helpful.

The NSRF asks if relays should be limited to electromechanical relays as the SPCS/SAMS Order 754 report identified risk depends upon the relay type and protection system design (meaning multiple relays to respond to a fault). If an entity shows no electromechanical primary or aux relays can that be sufficient to exclude from being redundant?

The NSRF asks if communications systems should be eliminated except for RAS. The SPCS/SAMS Order 754report identified communications systems posed a lower risk level.

Example NERC Defined Protection System Component Classes, Scope and Applicability:

NERC Bulk Electric System (BES) protective relays/sudden pressure relays/reclosing relays:

NERC BES PRC-005-6 Protection System electromechanical primary and auxillary relays are included in footnote 13. This includes PRC-005-6 identified sudden pressure and reclosing relays.

NERC BES associated communication systems:

NERC BES PRC-005-6 associated communication systems are included in footnote 13.

Redundant communications system for footnote 13 would be two communications channels. Redundant communications for Footnote 13 does not require separate and diversely routed communications towers.

NERC BES Voltage and current sensing devices:

NERC BES PRC-005-6 voltage and current sensing devices are not included in footnote 13. The SPCS/SAMS Order 754 report identified that voltage and current sensing devices were robust and posed a lower risk level.

NERC BES Station batteries:

NERC BES PRC-005-6 Station batteries are included in footnote 13 with the following exceptions. A single station DC supply is allowed if monitored for low voltage and open circuit alarms to a centrally monitored location within 24 hours of abnormal condition detection.

NERC BES Battery Chargers:

NERC BES PRC-005-6 station battery chargers are included in footnote 13.   A single station charger is allowed if the battery bank is monitored for low voltage and open circuit alarms to a centrally monitored location within 24 hours of abnormal condition detection.

NERC BES DC control circuitry:

NERC BES PRC-005-6 DC control circuitry is included in footnote 13 but its outcome is already considered in the P4 stuck breaker category. Whether stuck breaker of a DC control circuit failure, the end result is the same.

Likes 0	
Dislikes 0	

Response

Bridget Silvia - Sempra - San Diego Gas and Electric - 1,3,5

Answer	No
Document Name	
Comment	

Steady-state and stability software cannot not model directly the non-redundant components listed in footnote 13. Instead, the transmission planning engineer must simulate a component failure by deciding how the protection system will respond to the failure (which circuit breakers open and which don't) to clear the fault. Therefore, the engineer, not the software, will determine how the failure is simulated. For the purposes of the standard, the engineer may limit the Category P5 protection failures to those components found in footnote 13 and ignore any other possible single component failure. SDG&E recommends removal of footnote 13 and simplification of the P5 language to read, "Multiple Contingency (Fault followed by a protection failure resulting in multiple elements removed from service)". This would require that a fault followed by a protection system failure be assessed without consideration of protection system redundancy. If an issue is found, then the existing protection system would be reviewed for redundancy. If no redundancy exists, then addition of a redundant protection system can be part of the Corrective Action Plan. SDG&E recognizes that some TPs and PCs may object to doing protection failure simulations of fully redundant systems, but additional simulations can only improve system reliability.

Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 3,5	
Answer	No
Document Name	
Comment	

While AEP does not object to the concept itself of adding "communication system" to footnote 13, we believe its inclusion goes beyond the scope of the current SAR. We believe such an inclusion should not be considered until the SAR has been appropriately revised, and industry afforded opportunity to provide comment on the suggested change.

AEP requests additional clarification of footnote 13.4 regarding the phrase "through the trip coil(s) of the circuit breakers or other interrupting devices." In the data request associated with FERC Order 754 (Single Point of Failure on Protection Systems), local breaker failure protection was allowed to be modeled in cases of non-redundant trip coils. AEP recommends either changing the proposed text to allow the consideration of local breaker failure protection for trip coil failure (which has already been studied in P4), or instead, the elimination of the phrase altogether.

Likes 0	
Dislikes 0	
Response	
Hasan Matin - United Illuminating Co. - 1,3 - NPCC	
Answer	No
Document Name	
Comment	

While we agree with the clarification of components of a Protection System, we would like to see further clarification under P5 and the new Extreme Events (2e through 2h) as to where the fault and the failure of the components of a Protection System occur.

Is the intent of these new faults to have the fault and the failure of the component of the Protection System locally, remotely, or both?

Can this be added ("**local** failure of a non-redundant component of a Protection System", or "**remote** failure of a non-redundant component of a Protection System", or "**local and remote** failure (not simultaneously) of a non-redundant component of a Protection System") to the P5 and Extreme Events?

A fault locally along with a local failure of a component of a Protection System would be similar to NPCC's Criteria A-10 test, however, a fault locally with a remote failure of a component of a Protection System would be a scenario new to the industry, possibly leading many entities to discover scenarios where they have uncleared faults, however this may not be apparent to entities to be studied unless it's clarified in the standard.

Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	No
Document Name	
Comment	

1) Clarity needs to be added to “single relay” to exclude instances where a second relay performing a different function is also installed.

2) Clarity needs to be added to “single communication system” to specify the devices that need to clear a fault as opposed to devices that may result in overtrip.

3) Clarity should be added to allow for redundancy provided by devices responding to non-electrical quantities.

4) Clarity should be added for what constitutes “not monitored” or “not reported” in the instances of communication system and DC supply.

5) Clarity that redundant trip coils are not required.

Likes 0	
Dislikes 0	

Response

Chris Scanlon - Exelon - 1,3,5,6

Answer	No
Document Name	

Comment

The SPCS report on single point of failure did not include “a single communications system, necessary for correct operation of protective functions, which is not monitored or not reported”. The SPCS concluded that analysis of communications systems with regard to single points of failure did not pose enough of a risk to warrant addition in footnote 13. This assessment was based on SPCS efforts over the years studying blackouts/significant events and their causes. Communication system failures were not a causal factor in the significant events studied by the SPCS. Failures of relays and auxiliary relays have been causal in significant events. Thus, we agree with the SPCS assessment. We do agree with the drafting team that the vast majority of communications systems are monitored 24/7 to a central location. The few unmonitored systems on our system are applied at HV voltage levels where consequences of slow clearing are much less significant. PRC-005 already requires that unmonitored communications systems be tested on a frequent basis. In our case and likely for many others, this is sufficient motivation to create a program to add monitoring to unmonitored communications systems. All of these items relegate the addition of communication systems to footnote 13 to an exercise in documenting the low number of communications systems that are unmonitored. This addition then becomes purely burden with very little if any affect on our goal of providing an adequate level of reliability for the power system. Thus we recommend removing communication systems from footnote 13 in the revised standard.

Likes 0	
Dislikes 0	
Response	
larry brusseau - Corn Belt Power Cooperative - 1	
Answer	No
Document Name	
Comment	

Recommend that “Cascading” be replaced with a specific MW number such as the loss of 2,000 MW of generation as referenced in the EOP-004 standard. The term “Cascading” remains too vague and subject to change. A MW threshold is a better “bright line” criteria.

Recommend each BES Protection System component class be covered explicitly in Footnote 13 along with an inclusion or exclusion justification. Abrief Protection System scope for Footnote 13 may also be helpful.

Ask if relays should be limited to electromechanical relays as the SPCS/SAMS Order 754 report identified risk depends upon the relay type and protection system design

(meaning multiple relays to respond to a fault). If an entity shows no electromechanical primary or aux relays can that be sufficient to exclude from being redundant?

Ask if communications systems should be eliminated except for RAS. The SPCS/SAMS Order 754 report identified communications systems posed a lower risk level.

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circuit alarms to a centrally monitored location within 24 hours of abnormal condition detection.

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NERC BES PRC-005-6 station battery chargers are included in footnote 13.   A single station charger is allowed if the battery bank is monitored for low voltage and open circuit

alarms to a centrally monitored location within 24 hours of abnormal condition detection.

NERC BES DC control circuitry:

NERC BES PRC-005-6 DC control circuitry is included in footnote 13 but its outcome is already considered in the P4 stuck breaker category. Whether stuck breaker of a DC control circuit failure, the end result is the same.	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	No
Document Name	
Comment	

WAPA agrees with the intent but offers improvements to the language.

In Order No. 786 (P69), FERC declined to direct that NERC revise this standard to apply to all protection system components, at least until NERC completed its analysis of the Order No. 754 data responses. After review of that data, the NERC SPCS and SAMS recommended including protective relays, DC control circuitry, and station DC supply in the standard. This recommendation was based on the survey results regarding the prevalence of non-redundant protective equipment and the simulated disturbance magnitude of a failure of non-redundant equipment. The SPCS and SAMS report, did not, however, quantify the likelihood of each type of non-redundant protection component failure. Thus, it is hard to fully agree with the SPCS/SAMS recommendations at this time (and the Standard Authorization Request is only to “consider” them rather than “address” them).

WAPA does not believe that it is necessary to include analysis of all of these non-redundant Protection System component failures in the TPL standards at this time. Alternatively, if they are included, then they should be treated similarly to the current treatment of Extreme Events where there are no strict performance requirements or mandates to create Corrective Action Plans. In fact, the SPCS and SAMS report suggested that auxiliary relay and lockout relay failures were the main culprit in previous disturbances but failures of other equipment are generally rare or unimpactful (p.7). If anything, the P5 category expansion should be limited to auxiliary and lockout relays. This would allow utilities to focus their money and attention to mitigating the most severe potential impacts rather than building redundancy into systems where it will most likely never be needed.

WAPA recently studied the cost of eliminating single points of failure at a typical older substion. WAPA estimates that building full redundancy will likely cost over $1.3 million and take about a year and a half to implement. The main reason why it takes this long is due to scheduling outages. During outage timeframes, WAPA may have to curtail transmission or generation schedules, which many WAPA customers and staff would view as a decrement to reliable operations. The commissioning of new relays also requires significant testing, which conceivably puts WAPA at greater risk for human error. Furthermore, WAPA does not have any record of a P5 or EE2d type of event in the last 50+ years. Just building redundancy into substations will be a challenge to explain

to WAPA ratepayers, and it may prove extremely difficult if WAPA is required to add costs and time for DC control circuitry equipment. Instead, WAPA may desire to focus its limited resources on developing replacement plans for aging equipment (e.g. transformers) or improving security measures. As a reference, here is the language from SAMS Table 1.3. *DC Control Circuitry: The protection system includes two independent DC control circuits with no common DC control circuitry, auxiliary relays, or circuit breaker trip coils. For the purpose of this data request the DC control circuitry does not include the station DC supply or the main DC distributionpanel(s), but does include all the DC circuits used by the protection system to trip a breaker, including any DC control circuit (branch) fuses or breakers at the main DC distribution panel(s).* In addition to the concerns mentioned above, WAPA suggestions the following clarification of components of a protection system (Footnote 13). Suggested Language: For purposes of this standard, non-redundant components of a Protection System to consider are as follows: 1. A single protective relay which responds to electrical quantities used for primary protection; 2. A single communications system, necessary for correct operation of protective functions, which is not monitored or not reported; 3. A single DC supply associated with protective functions that is not monitored for both low voltage and open circuit, with alarms centrally monitored; 4. A single DC Control Circuitry that causes the primary and local backup protection system to not operate properly and triggers remote delayed clearing.

Likes 0	
Dislikes 0	

Response

Angela Gaines - Portland General Electric Co. - 1,3,5,6, Group Name PGE - Group 1	
Answer	No
Document Name	
Comment	

PGE does not agree with the inclusion of Footnote 13.3 *A single dc supply associated with protective functions, and that single station dc supply is not monitored or not reported for both low voltage and open circuit.* It is PGE's interpretation that this requirement is intended to address the potential failure of a

station battery when called upon to operate. The language in the footnote does not address monitoring the health of the battery, but instead addresses monitoring the battery charger. Monitoring voltage of a battery is really monitoring the operation of the battery charger. A functioning battery charger can mask a failed battery. Discharge testing of a battery is the only known reliable way to assess the batteries health. PGE does not agree with the inclusion of Footnote 13.4 *A single control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.* Table 1 requires that breaker failure be studied under Category P4. It is unclear how this footnote will add benefits and clarity to the TPL standard.	
Likes 0	
Dislikes 0	
Response	
Deborah VanDeventer - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
The further clarification is useful for the most part with one exception. SCE proposes that footnote 13, part 4 include an exclusion for single control circuitry with monitoring as done for parts 2 and 3. Currently the PRC-005-6 supplemental reference allows for maintenance programs to use both traditional time-based maintenance (minimum periodic intervals) and condition-based maintenance (continuously monitoring for inoperable components) to pre-emptively identify protection system issues and satisfy FERC's protection system verification directives from Order 693. SCE believes that trip coil/control circuitry monitoring should not only adequately mitigate any reliability risk that footnote 13, part 4 tries to capture, but can also be used in Corrective Action Plans where single control circuitry is not monitored and assessments demonstrate an impact to reliability. SCE recommends the following language for footnote 13, part 4: 4. A single control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices, which is not monitored.	
Likes 0	

Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
The clarity afforded by the device type was helpful in conducting inquires. AZPS suggests retaining the following sentence in Table 1, #13 regarding the type of relays the standard applies to: “Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).”	
Likes 0	
Dislikes 0	
Response	
Oliver Burke - Entergy - Entergy Services, Inc. - 1,5	
Answer	No
Document Name	
Comment	
IEEE recommended practices are used in designing typical generator protection schemes. Prevailing protection schemes (based on IEEE Standards) for a majority of generators that are in service may not have completely redundant protection schemes as clarified by proposed footnote 13. It may not be practical for GO/GOP to implement a completely redundant protection scheme. For example, it may not be physically possible to install additional CTs on the generators or redundant battery systems. The Standard Drafting Team should develop an application guideline with appropriate figures to clarify the Standard Drafting Team’s goal with this clarification. Refer to Figure 1.1 of NERC Technical	

Reference Document , "Power Plant and Transmission System Protection Coordination (http://www.nerc.com/docs/pc/spctf/Gen%20Prot%20Coord%20Rev1%20Final%2007-30-2010.pdf)	
Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
For P5, the probability of the occurrences of these component failures do not warrant a planning event. NIPSCO believes the current set of Planning events encompass the most likely to occur protection component failures, therefore P5 should remain as is. NIPSCO believes the addition of these components, specifically the single dc supply, will involve most BES facilities. This will create more extreme type contingencies involving loss of a complete substation. With most BES substations not having redundant protection components as the proposed footnote lists, the mitigations will result in unreasonable costs that were not intended by the standards or FERC Order 754. If these components are to be considered, it should remain as an extreme event.	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	

The defined components of the Protection system seemed to have made the intent and clarification unclear. While the footnotes add clarity to what single points of failure exist on protection systems, losing the language describing which types of relay are covered reduces clarity.	
Likes 0	
Dislikes 0	
Response	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	

Footnote 13 requires some changes. First of all, the P5 contingency event description clearly indicates that the P5 contingency only covers situations where there is "Delayed Fault Clearing due to the failure of a non-redundant component of a protection system to operate as designed". Therefore, it should be clarified in footnote 13 that any single component failure that results in overtripping , but not delayed fault clearing, should not be considered in the P5 contingency. For example, this would eliminate a single communications channel failure in a directional comparison blocking scheme (very common scheme for transmission line protection) from being considered a single-point of failure since this failure would result in overtripping, but not delayed fault clearing. However, a single channel communications failure for a permissive overreaching transfer trip scheme would be considered a single component failure since such a failure could result in delayed fault clearing.

Second, there is no mention of instrument transformer failure as a single component failure, but such failures could directly result in a failure to trip and thus subsequent reliance on delayed remote backup protection to clear the fault.   A NERC technical paper titled "Protection System Reliability – Redundancy of Protection System Elements", which was prepared by the NERC System Protection and Control Task Force and dated November 18, 2008, correctly indicates that instrument transformers can represent a single point of failure in a protection system as follows:

From Section 5.1 of the technical paper: "At least two isolated and separate AC current sources (referred to as CT inputs) for Protection Systems are required to meet the proposed requirement for CT redundancy. Figure 5-3 shows a common arrangement that addresses the current measurement redundancy requirement. CTs are required to provide totally separate secondary AC current sources for each redundant Protection System. This is required so that a shorted, open, or otherwise failed CT circuit will not remove all protection elements requiring current."

From Section 5.2 of the technical paper: "At least two separate secondary windings supplying voltages for Protection Systems are required to meet the proposed requirement for AC voltage source redundancy when such voltage sources are required to satisfy the BES performance required in the TPL standards. This is required so that a shorted, open, or otherwise failed voltage circuit will not remove all protection elements requiring voltage."

The proposed requirements outlined in the NERC technical paper align well with how most transmission owners have historically developed fully redundant protection schemes, and thus should be incorporated into Footnote 13 of the proposed TPL-001-5 standard.

Footnote 13 should clarify that a single protective relay means a single protective relay unit and not a single protective relay element. For example, a digital relay with multiple elements could experience a power supply failure, thus removing the functionality of all elements included in the relay unit. Therefore, using two relay elements in a single protective relay unit would not provide single-point-of-failure redundancy.

Footnote 13 should clarify that DC control circuitry specifically includes auxiliary relays and lockout relays, since such relays have often been the cause of single-point-of-failure events in the past. Furthermore, footnote 13 should clarify that only those DC control circuitry failures that do not result in merely a breaker failure operation should be checked. For example, if a circuit breaker includes only a single trip coil, but the DC circuitry that energizes the trip coil from redundant protective relays is isolated from the DC circuitry that initiates breaker failure from the same redundant protective relays via different output contacts, then a single trip coil is clearly part of the breaker and not part of the protection system since a failure of the trip coil results only in a P4 stuck breaker contingency (i.e., it would not cause a failure to initiate breaker failure, only a failure of the breaker to trip).

Also, the SDT may want to consider clarifying in Footnote 13 that only DC control circuitry associated with tripping circuit breakers should be considered when assessing whether or not there are single points of failure. That is, DC control circuitry required to close the circuit breaker would not cause delayed fault clearing through failure to trip, and should be excluded from the list in footnote 13.

Likes 0	
Dislikes 0	

Response

John Pearson - ISO New England, Inc. - 2 - NPCC

Answer	No
Document Name	

Comment

The parenthetical that specifies the different relay types should not be deleted because the term “single protective relay” is not specific enough. Also, the definition of the word “reported” included in the Rationale box should be moved to the footnote to make clear what “reported” means in numeral 3. As proposed, these sentences should read:

2. A single communications system, necessary for correct operation of protective functions, which is not reported within 24 hours of detecting an abnormal condition to a location where corrective action can be initiated.

3. A single dc supply associated with protective functions, and that single station dc supply is not reported within 24 hours of detecting an abnormal condition to a location where corrective action can be initiated for both low voltage and open circuit.

Likes 0	
Dislikes 0	
Response	
Darnez Gresham - Berkshire Hathaway - PacifiCorp - 6 - WECC	
Answer	No
Document Name	
Comment	

PacifiCorp agrees that additional footnote regarding further clarification of relay to components of a Protection System is helpful, but would request the drafting team to further clarify note 13 subpart 1 that the Transmission Planner include in the analysis only those single relays that are associated with isolation of fault. PacifiCorp believes that the note should be written as **“1. A single protective relay used for isolation of fault “**

Similar to comment above, note 13 subpart 2 should also clarify that communication required to isolate a fault should be redundant or monitored and reported. Also clarification as to what monitoring and reporting for the single communication systems should be performed to eliminate that as part of non-redundant protection system component would be helpful.

Likes 0	
Dislikes 0	

Response	
David Jendras - Ameren - Ameren Services - 1,3,6	
Answer	No
Document Name	
Comment	
We appreciate the attempt to further clarify the non-redundant components of a Protection System. However, from a planning perspective, it makes no difference as to why or what portion of the Protection System failed to operate and results in the delayed clearing. We are typically more interested in the most severe fault with the longest clearing time or the longest time delay. This change, if adopted, will likely require a change in our philosophy of running the most severe contingencies for each of the major substations, to running all contingencies to identify possible violations. This change as proposed will require a significant increase in stability analysis, and for very little benefit.	
Likes 0	
Dislikes 0	
Response	
Payam Farahbakhsh - Hydro One Networks, Inc. - 1,3	
Answer	No
Document Name	
Comment	
If the drafting team decided that the listed four items in Footnote 13 define single points of failure of Protection Systems, Hydro One suggests revised language in order to provide clarity for both the Planners as well as the P&C SMEs who will be called upon to evaluate the Protection Systems. We suggest the wording in the standard be clarified either directly or through appropriate descriptions in the rationale boxes. We also note that the 4 items in the footnote seem to be a mix of truly redundant components or singular components whose health is monitored. True Protection System redundancy to avoid single point of failure does not depend solely on health monitoring to meet redundancy requirements. We note and reference a previous work by the NERC SPCS concerning protection system redundancy entitled Protection System Reliability – Redundancy of Protection System Elements” (November 2008) where much of the wording in Footnote 13 and the corresponding rationale was derived from.	

Please consider the following comments and suggestions:

1. Table 1 Footnote 13.2 – (Also, reference Section 5.4 of NERC SPCS report)

Please clarify if the intent that a single monitored communication system necessary for correct operation of protection functions means that a single communication channel which is monitored meets the redundancy requirement. Quoting from the NERC SPCS report identifying redundant teleprotection schemes:

Some acceptable communication schemes are:

• Two power line carrier systems coupled to multiple phases of the line.

• Two microwave systems and paths with multiple antennas on a common tower.

• Two fiber paths between terminals (two fibers in the same cable are not acceptable)

• Two separate communication systems of different technologies and equipment (e.g., fiber

optic and digital microwave).

It would appear from the draft wording for this footnote that any singular communication channel, as long as it is monitored, does not need to be considered in the planning assessment. Please provide clarity on this through revised wording or in the rationale box. We believe that a communication channel is a component of the communication system. Unless this is clear, it may lead to confusion during the necessary Protection System assessments.

2. Table 1 Footnote 13.3 – (Also, reference Section 5.8 of the NERC SPCS report) – we have two concerns with this footnote where a single DC system which “is not monitored or not reported for low voltage and open circuit is considered non-redundant.” Firstly, it should be noted that in a single DC battery system, the RTU will likely also lose DC supply meaning a loss of DC supply alarm could not annunciate that specific condition to a control centre directly. Secondly, the use of the term “open circuit” is too broad. An open circuit in the battery system can be caused by many things, such as loose connections at the battery or any downstream DC breaker/fuse opening. We believe the intent of this footnote is to capture only the opening of the main protective device (breaker/fuse) after the DC system. In light of these 2 issues, we would like to suggest the following wording change to address these concerns:

13.3 A single DC supply associated with protection functions, and that single station DC supply is not monitored or not reported, either directly or indirectly, for both low voltage and for interruption of the station DC supply by the main protective device.” We believe this wording along with appropriate rationale would help clarify this footnote.

3. Table 1 Footnote 13.4 - (Also, reference Section 5.5, Section 5.6, and Section 5.7 of the NERC SPCS report) - If the drafting team considers monitoring for commumication system and DC supply to satisfy redundant requirements, then why can't trip coil monitoring be considered as well?	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no ISO-NE, NYISO and NextEra	
Answer	No
Document Name	
Comment	
Item #1 states a single relay, not a single protection package. Is our interpretation for item #1 that a package of (electromechanical) component relays (i.e. three relays in the single package) is redundant in accordance with TPL-001-5 correct? Since, within the sensitivity of the devices, a set of 3 phase and 1 ground relay detects any of the classic fault types (3PH, Ph-Ph, DLG, and SLG) with at least two (2) relays. We would like to provide an example with a transmission line that does not have two directional ground relays, but one directional distance relay (KD relay) per phase and one directional distance ground relay (IRD relay) for the SDT's review. With a single line to ground fault and the directional distance ground relay fails, the instant overcurrent relay will operate, but at a potentially different (e.g., slower) speed (depending on the fault current magnitude). In accordance with footnote 13, should the directional distance ground relay and the overcurrent relay be considered redundant, and hence not constitute a single point of failure per TPL-001-5? If the relays in the example are considered redundant, could we assume either relay to operate and hence do not need to consider them non-redundant components of a Protection System per footnote 13? Alternatively, if the relays in the example are considered non-redundant, do we need to test for operation of either of the two relays (i.e. both) per footnote 13? Item #2 does not specifically state anything about the speed of protection, although the associated rationale statement states that the evaluation shall address all Protection Systems affected by the failed component and the increases (if any) of the total fault clearing time. Is our interpretation for item #2 that one high speed and one step distance will provide a correct operation, so it doesn't need to be tested under footnote 13? Is our interpretation for item #2 that while a single communication system applied over a single communication medium which is not monitored or not reported constitutes a non-redundant component of a Protection System, a monitored pilot channels, such as FSK, is to be considered a redundant communication system in accordance with footnote 13? Further, is our interpretation for item #2 that this extends to on-off carrier channels with check-back testing so that only those without check-back reporting are considered non-redundant in accordance with footnote 13?	

It appears that the addition of “A single communications system, necessary for the correct operation of protective functions, which is not monitored or not reported” is beyond the scope of the SAR and the SPCS and SAMS recommendations in response to FERC Order No. 754. Please consider if this addition to footnote 13 is necessary.

Is our interpretation for item #3 that it is sufficient to monitor the battery and alarm if it is getting low correct in accordance with footnote 13? In other words, are we required to evaluate the failure of the battery, or is it sufficient to monitor for low battery voltage, while not knowing when it actually fails?

Could the SDT please provide further guidance in form of clarifying language or application guidance as related to item #4 in footnote 13? Is our interpretation related to item #4 that redundant relays tripping through a single wire to a single trip coil would constitute a non-redundant component of a Protection System? While item #4 does not seem to require dual trip coils, it seems to require dual wires. Does the last sentence provide a correct interpretation of a single control circuitry associated with protective functions through the trip coils of the circuit breakers or other interrupting devices per footnote 13?

Reference footnote 13, bullet 4: We recommend to replace the word “through” with “up to” to make the requirement clearer and less prone to different interpretations.

If the drafting team decided that the listed four items in Footnote 13 define single points of failure of Protection Systems, NPCC suggests revised language in order to provide clarity for both the Planners as well as the P&C SMEs who will be called upon to evaluate the Protection Systems. We suggest the wording in the standard be clarified either directly or through appropriate descriptions in the rationale boxes. We also note that the 4 items in the footnote seem to be a mix of truly redundant components or singular components whose health is monitored. True Protection System redundancy to avoid single point of failure does not depend solely on health monitoring to meet redundancy requirements. We note and reference a previous work by the NERC SPCS concerning protection system redundancy entitled Protection System Reliability – Redundancy of Protection System Elements” (November 2008) where much of the wording in Footnote 13 and the corresponding rationale was derived from.

Please consider the following comments and suggestions:

1. Table 1 Footnote 13.2 – (Also, reference Section 5.4 of NERC SPCS report) – Please clarify if the intent that a single monitored communication system necessary for correct operation of protection functions means that a single communication *channel* which is monitored meets the redundancy requirement. Quoting from the NERC SPCS report identifying redundant tele protection schemes:

Some acceptable communication schemes are:

• Two power line carrier systems coupled to multiple phases of the line.

• Two microwave systems and paths with multiple antennas on a common tower.

• Two fiber paths between terminals (two fibers in the same cable are not acceptable)

• Two separate communication systems of different technologies and equipment (e.g., fiber optic and digital microwave).

It would appear from the draft wording for this footnote that any singular communication channel, as long as it is monitored, does not need to be considered in the planning assessment. Please provide clarity on this through revised wording or in the rationale box. We believe that a communication channel is a component of the communication system. Unless this is clear, it may lead to confusion during the necessary Protection System assessments.

2. Table 1 Footnote 13.3 – (Also, reference Section 5.8 of the NERC SPCS report) – NPCC has two concerns with this footnote where a single DC system which “is not monitored or not reported for low voltage and open circuit is considered non-redundant.” Firstly, it should be noted that in a single DC battery system, the RTU will likely also lose DC supply meaning a loss of DC supply alarm could not annunciate that specific condition to a control center directly. Secondly, the use of the term “open circuit” is too broad. An open circuit in the battery system can be caused by many things, such as loose connections at the battery or any downstream DC breaker/fuse opening. We believe the intent of this footnote is to capture only the opening of the main protective device (breaker/fuse) after the DC system. In light of these 2 issues, we would like to suggest the following wording change to address these concerns:

“13.3 A single DC supply associated with protection functions, and that single station DC supply is not monitored or not reported, *either directly or indirectly*, for both low voltage and *for interruption of the station DC supply by the main protective device.”* We believe this wording along with appropriate rationale would help clarify this footnote.

3.Table 1 Footnote 13.4 - (Also, reference Section 5.5, Section 5.6, and Section 5.7 of the NERC SPCS report) - If the drafting team considers monitoring for communication system and DC supply to satisfy redundant requirements, then why can’t trip coil monitoring be considered as well?

We would like to see further clarification under P5 and the new Extreme Events (2e through 2h) as to where the fault and the failure of the components of a Protection System occur. Is the intent of these new faults to have the fault and the failure of the component of the Protection System locally, remotely, or both?

Can this be added (“local failure of a non-redundant component of a Protection System”, or “remote failure of a non-redundant component of a Protection System”, or “local and remote failure (not simultaneously) of a non-redundant component of a Protection System”) to the P5 and Extreme Events?

A fault locally along with a local failure of a component of a Protection System would be similar to NPCC’s Criteria A-10 test, however, a fault locally with a remote failure of a component of a Protection System would be a scenario new to the industry, possibly leading many entities to discover scenarios where they have un-cleared faults, however this may not be apparent to entities to be studied unless it’s clarified in the standard.

Likes 1	Chantal Mazza, N/A, Mazza Chantal
Dislikes 0	

Response

Jeffrey Watkins - Berkshire Hathaway - NV Energy - 6 - WECC	
Answer	No
Document Name	
Comment	
Clarification on communication-aided schemes is needed. The rational states that communication failures do need to be considered in the SPF analysis. Often, and general good utility practice is to provide separate communication paths for critical protection systems, such as redundant fiber on separate routes, fiber and microwave, diverse frequencies on the same microwave path, PLC on separate phases of a line, OPGW and PLC on a line, etc. Other, less redundant communication configurations are also possible such as multiple individual channels in the same fiber or microwave frequency and path or two OPGW cables on the same structure. • Is a communication configuration that uses this lower level of redundancy acceptable under the revised P5 and footnote 13? • Would monitoring and reporting failures of such “less or non redundant” communication facilities make them acceptable? • How about communication facilities that carry signals for RAS or other controls whose action may not be dependant on the physical telecommunication path? If the answers to any of these questions are “yes,” that would seem to contradict the SPCS white paper from 2009, which included several examples, in the discussion on communication redundancy. It may also provide a lower standard for communication compliance than for protective relay compliance. This would not appear to be a desirable reliability result.	
Likes 0	
Dislikes 0	
Response	

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

Duke Energy recommends the SDT consider that "*Non-redundant component*" be clarified to refer to "fault clearing initiating devices" leaving the wiring to the discretion of the results of the studies. (relays, carrier, battery, etc.) Duke Energy has concerns regarding the lack of information on what level of redundancy will be required. Based on the rationale provided, it appears that redundancy will not be required where cascading (result of a study) is not a concern, however, more clarity is needed regarding what redundancy would look like as it pertains to this standard. Where redundancy is required does this mean putting in a complete second system to meet compliance for item 4? *"4. A single control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices"?* Does separate circuits, mean separate in same panel or separate in separate panels. Does it mean separate cables in same conduit or separate cable in separate conduit, or could it mean separate conductor in same cable. Regarding redundancy of control circuits, does redundancy mean that separate trip coils are required in the breaker? More clarity is needed on this aspect to fully understand what compliance will look like. Also, regarding #2 in Footnote 13, where it says *"single communication system",* does this mean separate pairs in same cable, or does it mean fiber pair from two cables in two different paths? More clarity is needed on what the SDT's intent is for this language.	
Likes 0	
Dislikes 0	
Response	
Jameson Thornton - Pacific Gas and Electric Company - 1 - WECC	
Answer	No
Document Name	
Comment	
PG&E agrees that adding the components of a protection system to study provides clarity but the impact of this study is not known and more information is needed. The work required to respnd to the FERC ORDER 754 data request was significant and PG&E believes that this change may result in unduly burdensome activities without knowing what the full scope of non-redundant facilities are. Furthermore PG&E believes that the Transmission Owner may need to be added as an applicable entity to identify the facilities which do not meet the redundancy criteria specified here and assist in identifying the resulting outages and clearing times.	
Likes 0	

Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	

The SPP Standards Review Group suggests that on the rationale on page 23 of 33, there seems to be rationale missing, supporting communication- aided components of a protection system.

The SPP Standards Review Group suggests that in footnote 13, clarify that this is a finite list, and add some punctuation to define the list. Additionally, clarify Statement 4, and provide an explanation.

The SPP Standards Review Group suggests this would be more appropriately addressed in a PRC standard due to the protection scheme issues.

The SPP Standards Review Group suggests that the drafting team add clarity to the guidance document to address Directional Comparison Blocking (DCB) protection and whether or not it meets the intent of redundancy and what is meant by monitoring the communication system.

Likes 0	
Dislikes 0	
Response	
Eric Shaw - Oncor Electric Delivery - 1 - Texas RE	
Answer	No
Document Name	
Comment	

The potential cost of this to improve our system would be phenomenal. Even though it is only limited to 3-phase faults, this would produce additional burden to the annual planning assessment. NERC 754 required us to do this with the understanding that if there was such a scenario, it would not be counted as a violation. Now they are adding this to a point that it would be a violation.	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1 - SERC	
Answer	No
Document Name	
Comment	
Need footnotes to explain why items like PT’s and CT's are excluded.	
Likes 0	
Dislikes 0	
Response	
Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	

CenterPoint Energy disagrees with the further clarification. CenterPoint Energy recommends deleting item (b) in Footnote 13: “A single communications system, necessary for correct operation of protective functions, which is not monitored or not reported.” CenterPoint Energy’s recommendation is based on the following: • The System Protection and Control Subcommittee (SPCS) and System Modeling and Analysis Subcommittee (SAMS), after performing an extensive analysis by their subject matter experts, did not recommend including communication systems in Footnote 13 (Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request, September 2015). • A communication system was not part of the Standards Authorization Request as one of the non-redundant components of a Protection System to consider for inclusion in Footnote 13. • Monitoring communications equipment of communication-aided protections schemes is extensively utilized. In addition, NERC Standard PRC-005, Transmission and Generation Protection System Maintenance and Testing, encourages monitoring of communication systems, to avoid frequent manual testing, for entities that have no monitoring or entities that do not yet have monitoring of one hundred percent of their applicable communications systems. • The September 2015 SPCS/SAMS assessment noted that a communication system failure will not prevent high-speed tripping (i.e., does not result in Delayed Fault Clearing) for certain protection system designs, such as a directional comparison blocking scheme (DCB), which is extensively utilized. • Including communication systems in Footnote 13 results is a compliance burden that does not provide commensurate reliability benefits. CenterPoint Energy comments on the wording of the Rationale for Table 1 P5 Event and Footnote 13 are as follows: • The first sentence of the first paragraph states an entity must model a single point of failure of a non-redundant Protection System component “that may prevent correct operation of a Protection System…” CenterPoint Energy recommends replacing this phrase with: “that will result in Delayed Fault Clearing associated with a failure to trip.” CenterPoint Energy recommends deleting the second sentence: “The evaluation shall address all Protection Systems affected by the failed component and the increases (if any) of the total fault clearing time.” • In the second sentence of the fourth paragraph, CenterPoint Energy recommends adding that the SPCS/SAMS report also described a communication system as having a lower level of risk of failure to trip. • CenterPoint Energy recommends review of the fifth paragraph and Footnote 13d. The fifth paragraph states the team sought to limit the scope of protective relays to those used for “primary protection,” not including “backup protection.” However, the terms “primary” or “backup” protection are not used in Footnote 13 that uses the NERC term Protection System. Based on the NERC Glossary definition, a Protection System at a substation for an Element could include two, or more, protection schemes whether the schemes are called primary/backup, primary/secondary, or scheme 1/scheme2. • CenterPoint Energy concurs with the wording of Footnote 13 item (a) of “A single protective relay,” which does not include language that it applies only to protective relays “which responds to electrical quantities.” This allows the use, if appropriate, of a sudden pressure relay as redundant for transformer differential protection. Sudden pressure relays were addressed by the SPCS (Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities - SPCS Input for Standard Development in Response to FERC Order No. 758, December 2013)

Likes 0	
Dislikes 0	
Response	

Mark Riley - Associated Electric Cooperative, Inc. - 1,3,5,6, Group Name AECI & Member G&Ts	
Answer	No
Document Name	
Comment	
Item 2 goes beyond the scope of the SAR. Furthermore, specificity of the relay functions is preferred in order to eliminate the possibility of a different interpretation by an auditor.	
Likes 0	
Dislikes 0	
Response	
Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	
Answer	No
Document Name	
Comment	
The SRC offers the following comments regarding clarification of relay components of a Protection System: 1) Clarity needs to be added to "single relay" to exclude instances where a second relay performing a different function is also installed. 2) Clarity needs to be added to "single communication system" to specify the devices that need to clear a fault as opposed to devices that may result in overtrip. 3) Clarity should be added to allow for redundancy provided by devices responding to non-electrical quantities. 4) Clarity should be added for what constitutes "not monitored" or "not reported" in the instances of communication system and DC supply. 5) Item #4 is unclear if it is requiring two trip coils. This needs to be clarified. 6) Do the trip coils need to be monitored?	

7) It is not clear on how trip coils are to be evaluated. An application guide to provide more detail on and explain the proposed footnotes would be helpful.

8) Wouldn't the single control circuitry just be a concern up to the point of initiating breaker failure (not to the trip coil). In other words, as long as breaker failure is initiated, then the event would be captured under P4.

9) The parenthetical that specifies the different relay types should not be deleted because the term “single protective relay” is not specific enough.

10) While the revised footnote is an improvement, clarifications are still needed to properly identify the redundancy requirements. We believe that minimum design requirements or a guideline should be included in the standard. That will allow the Planning Coordinators/Transmission Planners to have a consistent interpretation of the footnote 13.

11) There are situations when non BES elements are connected to BES buses (e.g. radial circuits supplying loads). The standard must clarify which protection systems failures needs to be studied since an uncleared close in fault on a non BES element connected to a BES bus has the same consequence as an uncleared close in fault on a BES element.

12) Do the protection systems installed on non BES elements connected to BES buses and protecting portions of the BES buses need to meet redundancy criteria?

Likes 0	
Dislikes 0	

Response

Brandon McCormick - Florida Municipal Power Agency - 3,4,5 - FRCC

Answer	No
Document Name	

Comment

The FERC Order 754 SPCS report specifically recommended adding the components from the definition of protection system. Within that definition, protective relays are described as “Protective relays which respond to electrical quantities”. This is an important distinction which is missing from the proposed addition/revision to footnote 13.

Likes 0	
Dislikes 0	

Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
The footnote is unclear and requires additional clarity. After review by the System Protection Engineering group, they have determined that the drafting team's attempt to provide clarity falls short of its intent. Additionally The inclusion of 3phase faults in the Extreme events stability runs will require a substantial incease in the amount of stability files that need to be created, constantly reviewed, and ran on a regualar basis. This will greatly increase the burden on the TP.	
Likes 0	
Dislikes 0	
Response	
Long Duong - Public Utility District No. 1 of Snohomish County - 1,4,5	
Answer	No
Document Name	
Comment	
SNPD suggests replacing the entire footnote 13 with a simple statement "Fault followed by a failure of the Protection System resulting in delayed trip from local and remote substations." This objective would require an Entity to assess and validate potential event(s) within its Bulk Electric System. We also suggest the Drafting Team consider the loss of the station battery as an extreme event (Category P7) that causes no trip at the local station and the faulted event can only be cleared from remote trips (Delayed Fault Clearing.)	
Likes 0	
Dislikes 0	

Response	
faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Babik - JEA - 1,3,5	
Answer	Yes
Document Name	
Comment	
The clarification of relay to components of a Protection System along with the associated footnote 13 does add clarity to the category P5 Planning Events as well as extreme events.	
Likes 0	
Dislikes 0	
Response	
Dori Quam - NorthWestern Energy - 1,3 - MRO,WECC	
Answer	Yes

Document Name	
Comment	
Yes, but Item 4 of Footnote 13 needs clarification.	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Idaho Power agrees with the further clarification of relay to components since Protection System definition includes: • Protective relays which respond to electrical quantities, • Communications systems necessary for correct operation of protective functions • Voltage and current sensing devices providing inputs to protective relays, • Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and • Control circuitry associated with protective functions	
Likes 0	
Dislikes 0	
Response	
Shawn Abrams - Santee Cooper - 1,3,5,6, Group Name Santee Cooper	
Answer	Yes

Document Name	
Comment	
Comments: The clarification of relay to components of a Protection System along with the associated footnote 13 does add clarity to the category P5 Planning Events as well as extreme events.	
Likes 0	
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Peak supports the clarified language.	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Great Plains Energy - Kansas City Power and Light Co. - 1,3,5,6 - SPP RE	
Answer	Yes
Document Name	
Comment	

KCP&L agrees the language provides clarification but there is opportunity for further clarity as detailed in KCP&L's response to Question 4.	
Likes 0	
Dislikes 0	
Response	
Michael Haff - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	Yes
Document Name	
Comment	
Seminole endorses the comments submitted on this Project by JEA.	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 1,3,4	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Shelby Wade - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC,RF, Group Name PPL - Louisville Gas and Electric Co.	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeff Powell - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kayleigh Wilkerson - Lincoln Electric System - 1,3,5,6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe Tarantino - Sacramento Municipal Utility District - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1,5,6, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

John Merrell – Tacoma Public Utilities (Tacoma, WA) - 3	
Answer	No
Document Name	
Comment	

1. Tacoma Power does not agree that all parts of the Protection System should be treated identically with regards to single point failures. As identified the order 754 final report, some protection system components such as protective relays, auxiliary relays, and DC circuits downstream of the DC panel branch circuit protection have been documented as common causes of actual single point failures. The final report also identifies that AC inputs and the station DC supply pose much lower risk of failure to trip. The attached table shows an alternative set of contingencies that would implement a more risk-based approach to single point failures of each kind of component in the protection system.

2. Tacoma Power proposes P5 include the more common kinds of failures of the protection system that include 1) Protective relays which respond to electrical quantities; 2) A single communications system, necessary for correct operation of protective functions, which is not monitored; and 3) Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

3. New P8 and P9 contingencies for EHV facilities would address the remaining less likely to fail components of the protection system including (1) Voltage and current sensing devices providing inputs to protective relays, (2) Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply). Since these kinds of components are less likely to fail, allowing interruption of firm transmission service and nonconsequential load should be allowed for all voltage levels.

The 754 report found that only 0.7% of 100-199 kV buses had adverse system response from a single point of failure whereas 20% of EHV buses had adverse system response from a single point of failure. This disparity indicates efforts mitigating single component failures should be focused on the EHV system. The new P8 and P9 (i.e. the proposed d-h extreme events) should apply to just EHV elements. Creating new events P8 and P9 would clarify that Corrective Action Plans are required for these contingencies whereas extreme events do not require CAPs. 4. Tacoma Power supports reformatting of Table 1, as it is currently quite confusing. 5. There appears to be confusion as to whether to monitor protection circuits, the battery bank or the main DC breaker for open circuit. Trip coil monitoring does not provide any assurance the batteries are connected. Furthermore, there appears to be a lack of publicly available evidence that battery open circuit monitoring substantially lowers the risk of the protection system failing to trip. Dual batteries may be more appropriate for many EHV applications. 6. Battery monitoring system cost roughly the same amount as the set of batteries they monitor. Imposing additional costs for battery monitoring systems may lead to utilities replacing battery banks less often. 7. If the SDT continues to include monitoring as a viable option, these additional clarifications are need: (1) battery open circuit monitoring is required, (2) every breaker/fuse in the DC system must be monitored if it is a single point of failure, (3) a single trip coil is a single point of failure and is not mitigated by having trip coil monitoring unless there is independent breaker failure control circuitry, (4) low voltage monitoring threshold for battery voltage shall be coordinated with the battery design to give indication with at least 50% of battery capacity remaining, (5) auxiliary type relays for loss of DC may not be sufficient for low voltage monitoring of the battery, although they may be used for monitoring for loss of DC, and (6) non-battery-based DC systems require redundancy and should be addressed in a separate bullet under Footnote 13. 8. If monitoring of Protection System components is counted for purposes of TPL-001-5, is it the drafting team's intent that an entity would be obligated to maintain the alarming paths and monitoring systems under PRC-005-6 (Requirement R1, Part 1.2, and Table 2)? An entity should be allowed to consider monitoring for purposes of TPL-001-5 but treat the associated Protection System component(s) as unmonitored for purposes of PRC-005-6. 9. Additional clarification is requested on the demarcation between station DC supply and control circuitry for purposes of TPL-001-5. It is recommended that the main breaker of DC panels be considered part of the station DC supply.	
Likes 0	
Dislikes 0	
Response	

4. Do you agree with the proposed Requirement 4, Part 4.6 additions which require a Corrective Action Plan for this subset of Table 1 extreme events (footnote 13, 2e-2h)?	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
SRP believes events 2e-2h are significant enough to warrant their own category in the planning table (such as P8).	
Likes 0	
Dislikes 0	
Response	
Long Duong - Public Utility District No. 1 of Snohomish County - 1,4,5	
Answer	No
Document Name	
Comment	
SNPD agrees with simulating extreme events for the Near-Term Planning Assessment Study so we can learn from and understand the constraints of the BES and we can share results for situational awareness and work jointly with our PC/TP/TOP to develop short-term solutions. However, while it is feasible to study and develop an awareness of the BES for the Long-Range Planning Cases, SNPD suggests the Drafting Team not require a Corrective Action Plan(s) for the Long-Range Planning Cases, as it is not practical to require an Entity to develop a Long-Term Corrective Action Plan for extreme scenarios for the 5-year and beyond planning cases.	
Likes 0	
Dislikes 0	

Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
We conceptually disagree with *requiring* any mitigation for extreme events – this would be a deviation from the long-standing planning philosophy of assessing the risks and consequences to BES reliability for Category D contingencies (i.e. extreme events) and permitting the transmission planner to exercise its discretionary judgment to identify usage of any corrective action(s) to reduce system vulnerability to extreme events.	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Florida Municipal Power Agency - 3,4,5 - FRCC	
Answer	No
Document Name	
Comment	
We have three concerns with this addition in R4.6. First is that the appropriate location in the standard for determining what events require Corrective Action Plans is R2.7, not R4. The second concern is that no other extreme events currently mandate projects (CAPs) to address performance issues. FMPA can find no instance in which FERC ordered that assessments of failure of a component of a protection system with a three phase fault be required to be remedied with a CAP, and furthermore, we find no instance in the SPCS Order 754 report where this was stated either. By all accounts the explicit changes to Table 1 items 2e-2h and the changes to the P5 event should have addressed FERC's concerns and should have addressed the recommendations of SPCS in the Order 754 report. By including the new requirement R4.6, the drafting team is ostensibly concluding that any projects that are proposed to address 2e-2h will be inexpensive and "easy to fix". While that may be likely, it cannot be guaranteed. Throughought the standards and the standards development process, industry is routinely informed that standards are not mandating capital projects, but that is excactly what this requirement is doing. The third concern is that it will be difficult/complicated to demonstrate compliance with this requirement, for a number of reasons. First is that Cascading is nowhere near as cleanly defined and identified as "delayed clearing" is. Secondarily, if the goal of these simulations is now to find events that	

result in cascading, the table 1 criteria for identifying events that result in “delayed clearing” simply was not written with that goal in mind. It was written to look for events that have significant stability impacts/cause that cause disruptions within the power system. Delayed clearing does not equate to “cascading”. Where this comes into play is in assessing R4.4 contingency lists, where the PC and TP exercise engineering judgment to select which events will be the most severe. Since the Table 1 criteria for 2e – 2h specifically require delayed clearing, the PC or TP may select events in different locations.	
Likes 0	
Dislikes 0	
Response	
Gary Trent - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	No
Document Name	
Comment	
Extreme Events should not have mandated performance requirements. By their definition, Extreme Evenets are highly unlikely and the burden for mitigaton should be left up to the entities impacted.	
Likes 0	
Dislikes 0	
Response	
Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	
Answer	No
Document Name	
Comment	

The SRC does do not agree with the addition of Requirement 4, Part 4.6. We believe this addition contradicts with the basic design, planning and operation criteria of the BES, and exceeds the overarching objectives of achieving an adequate level of reliability.

The intent of assessing extreme events is to get a feel of how the system would perform under such conditions. Where possible, actions could be speculated or designed to mitigate the adverse impact, as already mandated in Part 4.5 of the existing TPL-001-4 standard. To go so far as requiring corrective action plans (CAP) to prevent or reduce the occurrence (such as by duplicating the non-redundant component) goes beyond the basic criteria for the design, planning and operation of the BES. Simply put, it goes beyond the adequate level of reliability. It might be fairly safe to say that quite a few entities will fail the extreme event testing under certain anticipated conditions for which the BES is not designed to withstand. Hence the existing requirement to evaluate possible actions to reduce the likelihood or mitigate the consequences of the event is appropriate, but to develop and implement CAPs for events (e) to (h) in Footnote 13 will incur in significant cost over and above what's needed to meet the basic criteria. This is philosophically, and in principle, a non-starter. We respectfully request the drafting team not to add this part.

Note: ERCOT does not support this comment.

Likes 0	
Dislikes 0	

Response

Michael Haff - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Answer	No
Document Name	

Comment

Seminole endorses the comments submitted on this Project by JEA.

Likes 0	
Dislikes 0	

Response

Mark Riley - Associated Electric Cooperative, Inc. - 1,3,5,6, Group Name AECI & Member G&Ts

Answer	No
Document Name	
Comment	
This change goes beyond the scope of the SAR. It essentially makes an Extreme Event equivalent to a Planning Event. Additionally, it is not clear whether the CAPs ever have to be built or if they just have to be on paper.	
Likes 0	
Dislikes 0	
Response	
Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy disagrees with the proposed Requirement 4, Part 4.6, additions. CenterPoint Energy's disagreement is based on the following: • The SPCS and SAMS, after performing an extensive analysis by their subject matter experts, did not recommend requiring a CAP for a subset of Table 1 extreme events (Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request, September 2015). • Requiring a CAP for a subset of Table 1 extreme events (footnote 13, 2e-2h) was not part of the Standards Authorization Request. • Requiring documentation of a CAP for a specific, limited subset of Extreme Events results in a compliance burden that does not provide commensurate reliability benefits. If the analysis concludes there is Cascading caused by the occurrence of Table 1 extreme events listed in the stability column for events 2e-2h, an evaluation of possible actions designed to reduce the likelihood, or mitigate the consequences and adverse impacts of the event, should be conducted the same as with any other Extreme Event analysis that concludes there is Cascading.	
Likes 0	
Dislikes 0	
Response	

Michael Shaw - Lower Colorado River Authority - 1,5,6, Group Name LCRA Compliance	
Answer	No
Document Name	
Comment	
The intent of 4.6 is already covered by the proposed changes to the P5 Category definition and reference to footnote 13. For instance, the EHV BES level does not allow for non-consequential load loss for a P5 contingency. In addition, the last sentence of 4.5 states "If the analysis concludes there is Cascading caused by the occurance of extreme events…an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences…shall be conducted." This statement effectively requires the development of alternatives. If there is a desire to strengthen 4.5 for events which lead to cascading related to non-redundant protection systems then it could be done in 4.5.	
Likes 0	
Dislikes 0	
Response	

Joe Tarantino - Sacramento Municipal Utility District - 1,3,4,5,6 - WECC	
Answer	No
Document Name	
Comment	
SMUD does not support the proposed changes; we do not agree with the addition of Requirement 4, Part 4.6. We believe this addition contradicts with the basic design, planning and operation criteria of the BES and exceeds the overarching objectives of achieving an adequate level of reliability. The concept of assessing extreme events is to obtain an understanding how the system would perform under such conditions. Where possible, actions could be speculated or designed to mitigate the adverse impact, as already mandated in Part 4.5 of the existing TPL-001-4 standard. Requiring corrective action plans (CAP) to prevent or reduce the occurrence (such as by duplicating the non-redundant component) goes beyond the basic criteria for the design, planning and operation of the BES. Any decision to assign resources in either prevention of an extreme event or the mitigation of impacts for an extreme event should be left to the discretion of the entities impacted rather than mandated by the standards	

Additionally, a corrective action plan implies a correction is necessary and could be interpreted as a mandatory action requiring full mitigation for impacts of the extreme events. Studies that evaluate the impact of these extreme events and identification of possible actions that would reduce the likelihood or mitigate the consequences of these event types, as appropriately covered in requirement R4.5.	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1 - SERC	
Answer	No
Document Name	
Comment	
Language should be very specific that the Implementation plan period is only for development of the CAP and not implementation of the CAP. It reads as if this remains open until the CAP is closed.	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	No
Document Name	
Comment	
The clarification of relay to components of a Protection System with the additional footnote to clarify P5 and extreme events – stability 2e-2h is a significant improvement to the proposed TPL-001-5. It addresses ALL the recommendations from SPCS and SAMS regarding single points of failure in protection systems in the report from Section 1600 Data Request following Order No. 754. This Order was issued directing NERC and Commission staff to initiate a	

process to identify any reliability issues for system performance following the loss of a single BES Element which appeared in the legacy TPL (version 0) standards. The conclusion from the report has rightfully and adequately addressed the Commission's concern. In general, the proposed TPL-001-5 removes the ambiguity from the legacy TPL standards for protection system failures.

However, the proposed new Requirement 4, Part 4.6 adding the Corrective Action Plan goes beyond the recommendation from the Section 1600 Data Request report for Order No. 754. In addition, the conclusion of the above report did not recommend setting the bar "higher" for performance than it is for current TPL-001-4 for extreme events in TPL-001-4 Part 4.5 nor did the SAR authorize the SDT

to do this. Any cascading due to an extreme event is already addressed in the Commission approved TPL-001-4 in Requirement 4, Part 4.5 wherein an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) is warranted. Besides, a cascading caused by the extreme event due to protection system single points of failure (Table 1 for P5 and extreme event – stability 2e-2h) is no different than a cascading due to any other extreme event (a cascading is a cascading; the end result is the same). And the Section 1600 Data Request report has very clearly put this in their conclusion in the second paragraph which is copied below verbatim:

"Additional emphasis in planning studies should be placed on assessment of three-phase faults involving protection system single points of failure. This concern (the study of protection system single points of failure) is appropriately addressed as an extreme event in TPL-001-4 Part 4.5. From TPL-001-4, Part 4.5: If the analysis concludes there is cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted."

The added clarification under Table 1 for Planning Event P5 and extreme event – stability 2e-2h along with footnote 13 sufficiently covers all the concerns that the Commission expressed in Order No. 754 as well as the conclusion and recommendation from the analysis for the same in the aforementioned report for the protection system single points of failure.

Besides, if Requirement 4, Part 4.6 goes into effect, there won't be any operational workaround on the cascading arising from such failures. The "only" Corrective Action Plan for these kinds of events is a new capital improvement project which will require a significant time and effort for coordination among PCs, TPs and the Facility owners and operators (TO/ TOP/ GO/ GOP). In addition, the installation/implementation of such Corrective Action Plans may cost the industry tens of billions of dollars with significant construction efforts spanning 10-20 years. This is a high-impact, low-frequency event risk that the industry, in order to identify and mitigate significant reliability risks, should develop action plans to reduce the likelihood or mitigate the consequences from such events keeping in mind their resources and budget which is already addressed in Requirement 4, Part 4.5.

Suggestion: Requirement 4, Part 4.6 is not needed.

Likes 0	
Dislikes 0	

Response

Eric Shaw - Oncor Electric Delivery - 1 - Texas RE	
Answer	No
Document Name	
Comment	
See comment #3.	
Likes 0	
Dislikes 0	
Response	
Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Also, the rationale to include 3 phase faults with the failure a non redundant component of a Protection System is too onereous. This scenario with a SLG fault is onerous enough. The requirements in the Extreme Events Table 2e-h should be depicted in Table 1 Planning Events as a second Row of P5 with three-phase as the "fault-type" for several reasons: 1. Table 1 note (a) already covers "cascading" not being allowed – maybe eliminating the need for a new R4.6 altogether 2. Clearly shows this as a signitifcant "raising-the-bar" event requiring a CAP 3. Maintains the separation between Planning Events (requiring a CAP) and Extreme Events (requiring analysis and optional CAP An alternative to it being depicted as a second row of P5 with three-phase as the "fault type" could be to make a P8 for stability only.	
Likes 0	

Dislikes 0	
Response	
Jameson Thornton - Pacific Gas and Electric Company - 1 - WECC	
Answer	No
Document Name	
Comment	
This is a duplication of R4.5. This is not identified in FERC order 768, we find no clear need for this additional language. Furthermore extreme contingencies have not required formal corrective actions plans, this may result in unduly burdensome activities for rare and unlikely events.	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
(1) Requirement R4 focuses on the performance of Contingency analyses reflective of Table 1 by applicable entities. We believe the development of a Corrective Action Plan to address a potential Cascading event, in the Transmission Planning Horizon, should be included as a separate requirement. The Correction Action Plan should account for all viable solutions, including the delay of implementing corrective actions until specific operating conditions have been met, as such actions could require significant capital investment to implement. (2) The SDT should clarify the reference to "Cascading" as only those Elements which pertain to the BES definition. By its current application, the reference could include any Element, including non-BES Facilities.	

(3) Furthermore, while the inability to implement a Corrective Action Plan could directly and adversely affect the electrical state or capability of the BES, thus aligning it with the criteria of a Medium Violation Risk Factor, the development of the plan, as proposed, does not. We believe the failure to develop a Corrective Action Plan is administrative in nature and constitutes a Lower Violation Risk Factor in the Long-Term Planning Horizon.

(4) Based on our experience, we have seen a shift in the development of Reliability Standards towards referencing terms like “Element” and “Facility” to collectively align with the BES definition. We propose removing references to “System” to both requirement parts and reword Part 4.6.1 to “List deficiencies and the associated actions needed to prevent Facilities from Cascading.”

Likes 0	
Dislikes 0	

Response

Jeffrey Watkins - Berkshire Hathaway - NV Energy - 6 - WECC

Answer	No
Document Name	

Comment

This subset of extreme events involves only 3Ø faults on various elements. In the presence of a Protection System SPF, this fault type may not be the most critical. The rational seems to anticipate that the revised criteria will be most applicable to legacy Protection Systems, since most newer PS are already designed using a higher level of redundancy. Many of the PS for these older schemes use single phase electromechanical or solid state relays. For such PS, a single relay failure would often not impact the ability to detect and clear a 3Ø fault, because two phase relays would still detect the fault and intiate clearing in the normally expected time *as though no relay failure had occurred*. The SPCS/SAMS report briefly alludes to this condition, but does not address an important System implication. A SLG fault on the same phase as the failed relay would not be detected within the primary protection zone and would result in delayed clearing. Of course, the number (System risk exposure) of SLG faults is much higher than for 3Ø faults. In most cases the same facilities are removed from service whether the delayed fault clearing results from a SLG or 3Ø fault. So, while it may initially sound counter intuitive, the more numerous SLG fault may actually have worse System impact than the 3Ø fault case with SPF.

- Does the drafting team interpret such SLG faults with Protection System failure as P5 (not extreme) events?
- If not, does it promote System reliability to not study the SLG fault case?

- If so, should another item be added to the list? The idea for such an item might read something like: If the non-redundant PS is implemented including single phase or ground relays, the e-h Element faults must also be studied for SLG faults with delayed fault clearing.

NVE would also like to suggest rewording Section 2 of the Stability portion of the Extreme Events table to help reduce wording,

2. Local or wide area events affecting the Transmission System such as:

- 3 phase fault on on any of the following equipment with stuck breaker resulting in Delayed Fault Clearing:

  - Generator
  - Transmission circuit
  - Transformer
  - Bus section

- 3 phase fault on any of the following equipment with failure of a non-redundant component of a Protection System resulting in Delayed Fault Clearing:

  - Generator
  - Transmission circuit
  - Transformer
  - Bus section

Likes 0	
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	
Answer	No
Document Name	

Comment	
The proposed requirement R4.6 represents a major shift with regard to extreme events. The current TPL-001-4 requires that extreme events be studied, but there are no performance requirement for these extreme event Contingencies, and these extreme event assessments do not result in Corrective Action Plans (CAP). According to the proposed set of requirements, if extreme events result in Cascading, a CAP must be developed that would prevent those extreme events from resulting in Cascading. Today, extreme events do not drive the development of CAPs; if this requirement as written is approved, extreme events will drive the development of CAPs. Peak's major concern with this requirement is any implied expectation for extreme events to be included and protected against in operations (including outage coordination assessments, OPAs, and RTAs). Such an expectation would have devastating consequences (economic consequences and reliability consequences) for operations. Given the implied potential for such operational expectations, Peak disagrees with the proposed requirement. Example. Let's say that a Planning Assessment includes a few planned outages and that the Planning Assessment indicates that an extreme Contingency results in Cascading. If the outage weren't in place, the extreme Contingency would not result in Cascading. The TP isn't going to build anything to address that Cascading, because it's a temporary condition due to the outage. So the TP creates a CAP which is an Operating Plan to "fix" it. Fast forward to operations. Is it presumed that this extreme Contingency is now credible for operations and that the system needs to be operated in a manner that prevents the extreme Contingency from resulting in Cascading? Peak is VERY reluctant to endorse any kind of planning standard that in any way can be perceived to dictate to operations which Contingencies (beyond single Contingencies) must be protected against in operations…ESPECIALLY extreme event Contingencies. This approach removes the ability of the RC and TOPs within the RC Area to operate the system to manage risk when it comes to deciding which Contingencies beyond single P1 Contingencies need to be protected against. Peak believes that Planning Assessment of extreme event Contingencies and the resulting development of an associated CAP should in no way imply that those extreme event Contingencies need to be protected against in operations.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no ISO-NE, NYISO and NextEra	
Answer	No
Document Name	
Comment	

Traditionally the intent of “extreme events” or “extreme contingencies” was to create awareness of the impacts of the studied contingencies, but not establish design requirements. Therefore, we recommend moving Table 1 Extreme Events Stability elements 2e through 2h from the Extreme Events table to Table 1 Planning Events, under a new Category P8, with the following attributes:

Category: P8 Multiple Contingency

Initial Condition: Normal System

Event: 2e through 2h

Fault Type: 3 phase

BES Level: HV, EHV

Interruption of Firm Transmission Service Allowed: Yes

Non-Consequential Load Loss Allowed: Yes

With this change, Requirement R4.6 should be revised as follows: “If the analysis concludes there is Cascading caused by the occurrence of Table 1 planning events P8, a Corrective Action Plan shall be developed….”

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

From our perspective, requiring the development of corrective action plans to include redundant relaying for extreme events is inconsistent compared with the existing TPL-001-4 requirements. Corrective action plans should include upgrades to meet planned events and local transmission planning criteria, but not for extreme events that have a very low probability of occurrence. If NERC/FERC wants redundant system protection systems to address these extreme events, then these requirements would be better suited to a PRC standard, and not a TPL standard. Transmission Planners should not be burdened with identifying which circuits are critical for which season or system condition so that protection engineers must install redundant system protection systems, which may only be needed for limited and specific system conditions.

We believe that further clarification is needed on Stability item 2f from Table 1 – Extreme Events. We believe that the terms "close-in" should be added to item 2f, so that it reads "3-phase close-in fault on Transmission circuit with failure of a non-redundant component of a Protection System resulting in Delayed Fault Clearing". We believe this change would reduce the number of scenarios that would need to be investigated from a stability perspective. Further, FERC Order 754 study only looked at close-in line and bus faults with remote clearing. For end of line 3-phase faults, fault detection is unlikely with a failure of a non-redundant System Protection Component due to in-feed effect. Therefore, it may not be possible to perform a reasonably valid stability study with this indeterminate state. If so, we believe that corrective action plans may be burdensome to complete. Given the low probability of a battery failure concurrent with a 3-phase end of line fault, we believe that inclusion of such events in the basic planning requirements is inconsistent.

Likes 0	
Dislikes 0	

Response

Darnez Gresham - Berkshire Hathaway - PacifiCorp - 6 - WECC

Answer	No
Document Name	

Comment

A 3-ph fault is a very low probability event and should be mitigated through operating plans if the contingency shows that it results in cascading just like the other extreme events. PacifiCorp agrees that a list of reliability issues for the extreme events (2e-2h) should be developed such that operating plans can be developed, but requiring system upgrades as part of a corrective action plan is a significant burden on utilities without added benefit over an operating plan. Hence PacifiCorp recommends the drafting team remove the requirement of having a corrective action plan for such a rare event.

Likes 0	
Dislikes 0	

Response

Shawn Abrams - Santee Cooper - 1,3,5,6, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	
Comments: This requirement goes beyond the recommendation from the Section 1600 Data Request report for Order 754. The report did not recommend setting the bar "higher" for performance than it is for current TPL-001-4 R4 Part 4.5 for extreme events. Additionaly, the SAR did not authorize the SDT to do this. Recommend removing R4 Part 4.6.	
Likes 0	
Dislikes 0	
Response	

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	
Requirement 4.5 of the TPL-001-4 standard has specified for the TPs/PCs "If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted". There is no justification given for why these particular extreme events should have more stringent requirements than other extreme events. A Corrective Action Plan (CAP) for extreme events should not be necessary, can be costly, and may not produce much benefit because of the low frequency of these type of events from happening. Suggestion: The addition of requirement 4.6 is not needed.	
Likes 0	
Dislikes 0	
Response	

Lauren Price - American Transmission Company, LLC - 1

Answer	No
Document Name	
Comment	

ATC does not agree with requiring the development of Corrective Action Plans (CAPs) for extreme stability 2e-2h events, or any other extreme events. We believe that the distinction between developing CAPs for “planning events” and not for “extreme events” is to recognize that the probability of extreme events is too low and the **cost to benefit ratio is too high to require the development of CAPs.** Part 4.5 already requires the evaluation of possible actions to reduce the likelihood or mitigate the consequences for all extreme stability events, including extreme stability 2e-2h events if there is Cascading. In addition, Part 3.5 also requires the evaluation of possible actions to reduce the likelihood or mitigate the consequences for extreme steady state events and there is no proposal for a Part 3.6 to require CAPs for any subset of steady state extreme events. (1) Is the intent of these CAPs to understand the scope of resolving the impact of the Extreme Events or to spend capital to resolve the issues?

Likes 0	
Dislikes 0	
Response	

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 1,3,5,6

Answer	No
Document Name	
Comment	

As stated in question 3, NIPSCO believes the addition of these components will involve most BES facilities. This will create more extreme type contingencies involving loss of a complete substation. Requiring a CAP on an extreme contingency on the amount of BES substations involved will lead to unreasonable mitigation costs. NIPSCO believes the requirement for all extreme events should suffice and the addition of proposed Requirement 4, Part 4.6 is unnecessary.

If the intention of the SDT was to require a plan of action, with no time limit on acting on these plans, as Part 4.6 reads, then again, the current requirement for all extreme events should suffice.	
Likes 0	
Dislikes 0	
Response	
Oliver Burke - Entergy - Entergy Services, Inc. - 1,5	
Answer	No
Document Name	
Comment	
As stated in response to Question 3 and repeated for emphasis, IEEE recommended practices are used in designing typical generator protection schemes. Prevailing protection schemes (based on IEEE Standards) for a majority of generators that are in service may not have completely redundant protection schemes as clarified by proposed footnote 13. It may not be practical for GO/GOP to implement a completely redundant protection scheme. For example, it may not be physically possible to install additional CTs on the generators or redundant battery systems. The Standard Drafting Team should develop an application guideline with appropriate figures to clarify the Standard Drafting Team's goal with this clarification. Refer to Figure 1.1 of NERC Technical Reference Document , "Power Plant and Transmission System Protection Coordination (http://www.nerc.com/docs/pc/spctf/Gen%20Prot%20Coord%20Rev1%20Final%2007-30-2010.pdf) Also, GO/GOP may not be able to implement corrective action schemes identified by the TP.	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1,3,5,6	
Answer	No
Document Name	

Comment	
For Table 1 Stability Performance events 2b, 2c, 2d, 2f, 2g, and 2h it is required to simulate a 3-phase fault. This contradicts with the fault type (single-line-ground) recommended for category P5 in the same Table.	
Likes 0	
Dislikes 0	
Response	
Deborah VanDeventer - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
The concern is that the method the drafting team chose to implement the language seems out of order with the technical nature and system planning intent of Extreme Event contingency analysis. A better solution might be to create a new contingency category (e.g., P8) for 3 phase faults coinciding with protection system failures and also add the corresponding requirement under R2 where failure to meet the performance thresholds from R6 require a Corrective Action Plan. This will align with other TPL contingency analysis and also allow for Planning Coordinators to define more tailored mitigation requirements for its Planning Coordinator area. Additionally, putting the Corrective Action Plan requirement under R2 aligns with other Table 1 performance violations.	
Likes 0	
Dislikes 0	
Response	
Angela Gaines - Portland General Electric Co. - 1,3,5,6, Group Name PGE - Group 1	
Answer	No
Document Name	

Comment	
Although PGE agrees that these single points of failure should be studied and identified, PGE does not agree with the requirement to develop a Corrective Action Plan. Corrective Action Plans are associated with capital improvements to add redundancy to the system. Adding redundancy to the system does not eliminate the possibility of an event, it only reduces the likelihood of the event. PGE recommends that utilities be given latitude to determine acceptable risk tolerances for events based on the likelihood of an event occurring and the consequence of that event. For example, it may be more likely for two old and unmaintained batteries to fail when called upon to act than one new and tested battery. The first case meets the requirement of the standard, while not providing system resiliency while the second would not meet the standard but could be a more economical and effective solution. The addition of a second battery to an existing substation could require rewiring or replacing existing relays or control buildings, replacing existing single trip coil breakers, and new trench systems. The cost of adding a second battery could be very high compared to alternative of assessing and managing the health of an existing battery to reduce the likelihood of failure. PGE recommends that the TPL standard offer performance criteria requirements in place of design requirements such as duel battery systems via Corrective Action Plans. The inclusion of Footnote 13.2 *A single communications system, necessary for correct operation of protective functions, which is not monitored or not reported* may have unintended consequences. If a utility has implemented transfer trip to improve coordination, but not because transfer trip is required for system stability, a utility might elect to disable transfer trip rather than incur the addition costs of demonstrating compliance with this requirement. As an alternative, it may be more beneficial to require that the critical clearing time for all facilities be studied, and entities are required to report facilities with critical clearing times greater than that of the backup protection where there is a non-redundant communication path, and to develop Corrective Action Plans.	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	No
Document Name	Project_2015-10_TPL-001-5_Unofficial_Comment_Form_V3 Planning Final.docx
Comment	

The additions which require a Corrective Action Plan for the subset of Table 1 extreme events (footnote 13, 2e-2h) are beyond what is stated in the conclusion of the SPCS and SAMS “Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request” report. This report recommended the following:

Modify TPL-001-4 (Part 4.5) so that extreme event assessments must include evaluation of the three-phase faults the described component failures of a Protection System13 that produce the more severe system impacts. For example, add a new second sentence that reads “[t]he list shall consider each of the extreme events in Table 1 – Steady State & Stability Performance Extreme Events; Stability column item number 2.”

Corrective Action Plans for low probability extreme events should not be required. However, it is reasonable that if Cascading is caused by the occurrence of an extreme event, an evaluation of possible actions designed to reduce the likelihood be conducted, as is currently stated in TPL-001-4 for extreme events (R4.5). Based on the conlusion of the above mentioned SPCS and SAMS report, it is understood that the intent should be to clarify that **both** three-phase faults with stuck breaker **and** failure of a non-redundant component of a Protection System13 resulting in Delayed Fault Clearing shall be considered as part of those extreme events in Table 1 that are expected to produce more severe System impacts in accordance with the existing language of TPL-001-4 R4.5. In other words, clarify that the “or” in Table 1 – Extreme Stability Events should not be interpreted as you only need to consider either stuck breaker or relay failure in R4.5. This is accomplished by simply breaking these events apart in Table 1 as shown below (and as in the current TPL-001-5 draft):

1. Local or wide area events affecting the Transmission System such as:

    i. 3Ø fault on generator with stuck breaker10 resulting in Delayed Fault Clearing.

    ii. 3Ø fault on Transmission circuit with stuck breaker10 resulting in Delayed Fault Clearing.

    iii. 3Ø fault on transformer with stuck breaker10 resulting in Delayed Fault Clearing.

    iv. 3Ø fault on bus section with stuck breaker10 resulting in Delayed Fault Clearing.

    v. 3Ø fault on generator with failure of a non-redundant component of a Protection System13 resulting in Delayed Fault Clearing.

    vi. 3Ø fault on Transmission circuit with failure of a non-redundant component of a Protection System13 resulting in Delayed Fault Clearing.

    vii. 3Ø fault on transformer with failure of a non-redundant component of a Protection System13 resulting in Delayed Fault Clearing.

    viii. 3Ø fault on bus section with failure of a non-redundant comoponent of a Protection System13 resulting in Delayed Fault Clearing.

    ix. 3Ø internal breaker fault.

    x. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

To further emphasize this point, refer to the alternatives for addressing reliability risks associated with single points of failure outlined in Charper 2 of the SPCS and SAMS report: · *Place additional emphasis on assessment of a three-phase fault and protection system failure* o *Provideds assurance that areas where a three-phase fault accompanied by a single point of failure that will cause an adverse impact are identified and evaluated* · *Elevate to a planning event with its own system performance criteria* o *Probability of three-phase fault with a protection system failure is low enough that it does not warrant a planning event* · *Keep as an extreme event with no change (other than footnote 13)* o *Does not provide assurance a three-phase fault with protection system failure is studied in planning assessments* From the above language describing the considered alternatives, it can be ascertained that the concern is ensuring that the language in the standard be updated to assure three-phase faults with protection system failure are studied in planning assessments, not that a "subset of Table 1 Extreme Events" be created that are treated differently than other Extreme Events by elevating them to requiring Corrective Action Plans because "the probability of three-phase faults with a protection system failure is low enough that it does not warrant a planning event". Furthermore, there is no technical justification to elevate a three-phase fault with failure of a non-redundant component of a Protection System events above three-phase fault with stuck breaker events. Although WAPA strongly disagrees with requiring a Corrective Action Plan for this "subset of Table 1 extreme events", if this requirement is carried forward WAPA recommends creating a separate P8 Event for these three-phase failure of a non-redundant component of a Protection System events because it makes Table 1 clearer to read, understand and differentiate between what is required of these events compared to other Extreme Events. **(see uploaded file Q/A #4)**	
Likes 0	
Dislikes 0	
Response	
Dori Quam - NorthWestern Energy - 1,3 - MRO,WECC	
Answer	No
Document Name	

Comment	
Since a Corrective Action Plan is not required, there is no need to create one. Corrective Action Plans would “gold plate” the system for very unlikely events.	
Likes 0	
Dislikes 0	
Response	
ALAN ADAMSON - New York State Reliability Council - 10	
Answer	No
Document Name	
Comment	
We agree that an evaluation of a list of system deficiencies and associated actions needed to prevent the system from cascading for extreme events 2e-2h should be required; however, we disagree that TPL-001-5 should further require implementation of Corrective Action Plans to mitigate these extreme events. Instead, Transmission Planners and Planning Coordinators should be required to consider implementing actions – recognizing cost and other factors – to reduce the likelihood or completely avoid the consequences of these extreme events.	
Likes 0	
Dislikes 0	
Response	
larry brusseau - Corn Belt Power Cooperative - 1	
Answer	No
Document Name	
Comment	

The additions which require a Corrective Action Plan for the subset of Table 1 extreme events (footnote 13, 2e-2h) are beyond what is stated in the conclusion of the SPCS and SAMS "Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request" report. This report recommended the following:

Modify TPL-001-4 (Part 4.5) so that extreme event assessments must include evaluation of the three-phase faults the described component failures of a Protection System[13] that produce the more severe system impacts. For example, add a new second sentence that reads "[t]he list shall consider each of the extreme events in Table 1 – Steady State & Stability Performance Extreme Events; Stability column item number 2."

Corrective Action Plans for low probability extreme events should not be required. However, it is reasonable that if Cascading is caused by the occurrence of an extreme event, an evaluation of possible actions designed to reduce the likelihood be conducted, as is currently stated in TPL-001-4 for extreme events (R4.5). Based on the conlusion of the above mentioned SPCS and SAMS report, it is understood that the intent should be to clarify that **both** three-phase faults with stuck breaker **and** failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing shall be considered as part of those extreme events in Table 1 that are expected to produce more severe System impacts in accordance with the existing language of TPL-001-4 R4.5. In other words, clarify that the "or" in Table 1 – Extreme Stability Events should not be interpreted as you only need to consider either stuck breaker or relay failure in R4.5. This is accomplished by simply breaking these events apart in Table 1 as shown below (and as in the current TPL-001-5 draft):

2. Local or wide area events affecting the Transmission System such as:
    a. 3Ø fault on generator with stuck breaker[10] resulting in Delayed Fault Clearing.
    b. 3Ø fault on Transmission circuit with stuck breaker[10] resulting in Delayed Fault Clearing.
    c. 3Ø fault on transformer with stuck breaker[10] resulting in Delayed Fault Clearing.
    d. 3Ø fault on bus section with stuck breaker[10] resulting in Delayed Fault Clearing.
    e. 3Ø fault on generator with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.
    f. 3Ø fault on Transmission circuit with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.
    g. 3Ø fault on transformer with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.
    h. 3Ø fault on bus section with failure of a non-redundant comoponent of a Protection System[13] resulting in Delayed Fault Clearing.
    i. 3Ø internal breaker fault.
    j. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

To further emphasize this point, refer to the alternatives for addressing reliability risks associated with single points of failure outlined in Charper 2 of the SPCS and SAMS report:

- *Place additional emphasis on assessment of a three-phase fault and protection system failure*
    - *Provideds assurance that areas where a three-phase fault accompanied by a single point of failure that will cause an adverse impact are identified and evaluated*
- *Elevate to a planning event with its own system performance criteria*
    - *Probability of three-phase fault with a protection system failure is low enough that it does not warrant a planning event*

- *Keep as an extreme event with no change (other than footnote 13)*
    - *Does not provide assurance a three-phase fault with protection system failure is studied in planning assessments*

From the above language describing the considered alternatives, it can be ascertained that the concern is ensuring that the language in the standard be updated to assure three-phase faults with protection system failure are studied in planning assessments, not that a "subset of Table 1 Extreme Events" be created that are treated differently than other Extreme Events by elevating them to requiring Corrective Action Plans because "the probability of three-phase faults with a protection system failure is low enough that it does not warrant a planning event". Furthermore, there is no technical justification to elevate a three-phase fault with failure of a non-redundant component of a Protection System events above three-phase fault with stuck breaker events.

Although Corn Belt strongly disagrees with requiring a Corrective Action Plan for this "subset of Table 1 extreme events", if this requirement is carried forward Corn Belt recommends creating a separate P8 Event for these three-phase failure of a non-redundant component of a Protection System events because it makes Table 1 clearer to read, understand and differentiate between what is required of these events compared to other Extreme Events.

Likes 0	
Dislikes 0	

Response

John Babik - JEA - 1,3,5

Answer	No
Document Name	

Comment

The clarification of relay to components of a Protection System with the additional footnote to clarify P5 and extreme events – stability 2e-2h is a significant improvement to the proposed TPL-001-5. It addresses ALL the recommendations from SPCS and SAMS regarding single points of failure in protection systems in the report from Section 1600 Data Request following Order No. 754. This Order was issued directing NERC and Commission staff to initiate a process to identify any reliability issues for system performance following the loss of a single BES Element which appeared in the legacy TPL (version 0) standards. The conclusion from the report has rightfully and adequately addressed the Commission's concern. In general, the proposed TPL-001-5 removes the ambiguity from the legacy TPL standards for protection system failures.

However, the proposed new Requirement 4, Part 4.6 adding the Corrective Action Plan goes beyond the recommendation from the Section 1600 Data Request report for Order No. 754. In addition, the conclusion of the above report did not recommend setting the bar "higher" for performance than it is for current TPL-001-4 for extreme events in TPL-001-4 Part 4.5 nor did the SAR authorize the SDT to do this. Any cascading due to an extreme event is already addressed in the Commission approved TPL-001-4 in Requirement 4, Part 4.5 wherein an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) is warranted. Besides, a cascading caused by the extreme event due to protection system

single points of failure (Table 1 for P5 and extreme event – stability 2e-2h) is no different than a cascading due to any other extreme event (a cascading is a cascading; the end result is the same). And the Section 1600 Data Request report has very clearly put this in their conclusion in the second paragraph which is copied below verbatim: ***“Additional emphasis in planning studies should be placed on assessment of three-phase faults involving protection system single points of failure. This concern (the study of protection system single points of failure) is appropriately addressed as an extreme event in TPL-001-4 Part 4.5. From TPL-001-4, Part 4.5: If the analysis concludes there is cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.”*** The added clarification under Table 1 for Planning Event P5 and extreme event – stability 2e-2h along with footnote 13 sufficiently covers all the concerns that the Commission expressed in Order No. 754 as well as the conclusion and recommendation from the analysis for the same in the aforementioned report for the protection system single points of failure. Besides, if Requirement 4, Part 4.6 goes into effect, there won’t be any operational workaround on the cascading arising from such failures. The “only” Corrective Action Plan for these kinds of events is a new capital improvement project which will require a significant time and effort for coordination among PCs, TPs and the Facility owners and operators (TO/ TOP/ GO/ GOP). In addition, the installation/implementation of such Corrective Action Plans may cost the industry tens of billions of dollars with significant construction efforts spanning 10-20 years. This is a high-impact, low-frequency event risk that the industry, in order to identify and mitigate significant reliability risks, should develop action plans to reduce the likelihood or mitigate the consequences from such events keeping in mind their resources and budget which is already addressed in Requirement 4, Part 4.5. **Suggestion**: Requirement 4, Part 4.6 is not needed.

Likes 0	
Dislikes 0	

Response

Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	No
Document Name	
Comment	
A corrective action plan should not be “required” for a combination of low probability events (3 phase fault coupled with a relay failure)	

Likes 0	
Dislikes 0	
Response	
Jeff Powell - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
TVA believes the occurence of a three-phase fault including a protection system failure would have an extremely low probability of occurring. As such, requiring implementation of a corrective action plan to fix these extremely rare events would cause a large and unnecessary financial burden with little benefit to our system reliability.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA believes that past performance can be a good indicator of future performance. These types of outages have not been an issue in the past. BPA believes that it is not economically justifiable to require corrective action plans for low probability extreme events like these. Instead, BPA believes an effort to minimize the likelihood of cascading should be considered, if studies indicate there is the potential for cascading on critical parts of the system.	
Likes 0	

Dislikes 0	
Response	
Thomas Foltz - AEP - 3,5	
Answer	No
Document Name	
Comment	
Similar to our response to Q3, AEP believes that pursuing Corrective Action Plans as part of R4, Part 4.6 goes beyond the scope of the current SAR. Once again, we believe such an inclusion should not be considered until the SAR has been appropriately revised, and industry afforded opportunity to provide comment on the suggested change. As to the concept itself, AEP does not agree that Correction Action Plans would be justified or necessary in every case. Considerations such as the nature and/or extent of any potential cascading should be a factor in determining whether or not a CAP is necessary, but as currently written, the obligation does not allow such engineering judgment.	
Likes 0	
Dislikes 0	
Response	
Bridget Silvia - Sempra - San Diego Gas and Electric - 1,3,5	
Answer	No
Document Name	
Comment	
SDG&E is not against trying to simulate the extreme contingency events listed in Table 1, 2e-2h, but simulations of extreme events often end with a simulation failure. TPL-001 is a mandatory requirement and this makes section 4.6 binding on the TP/PC. If a simulation fails, the TP/PC will have no choice but to create a Corrective Action Plan. Regardless of cascading.	
Likes 0	

Dislikes 0	

Response
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF

Answer	No
Document Name	

Comment

There are concerns with requiring the development of Corrective Action Plans (CAPs) for extreme stability 2e-2h events, or any other extreme events. The distinction between developing CAPs for "planning events" and not for "extreme events" is to recognize that the probability of extreme events is too low and the cost to benefit ratio is too high to require the development of CAPs. Part 4.5 already requires the evaluation of possible actions to reduce the likelihood or mitigate the consequences for all extreme stability events, including extreme stability 2e-2h events if there is Cascading. In addition, Part 3.5 also requires the evaluation of possible actions to reduce the likelihood or mitigate the consequences for extreme steady state events and there is no proposal for a Part 3.6 to require CAPs for any subset of steady state extreme events.

Is the intent of these CAPs to understand the scope of resolving the impact of the Extreme Events or to spend capital to resolve the issues?

The NSRF suggests the SDT mine the Event Analysis data to determine how many dynamic stability events occurred due to the lack of a redundant protection system component covered under Footnote 13. The benefit is the reduction and severity of events, while the costs could be significant.

Likes 0	
Dislikes 0	

Response
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6

Answer	No
Document Name	

Comment

Traditionally the intent of “extreme events” or “extreme contingencies” was to create awareness of the impacts of the studied contingencies, but not establish design requiements. Therefore we recommend moving Table 1 Extreme Events Stability elements 2e through 2h from the Extreme Events table to Table 1 Planning Events, under a new Category P8, with the following attributes: Category: P8 Multiple Contingency Initial Condition: Normal System Event: 2e through 2h Fault Type: 3 phase BES Level: HV, EHV Interruption of Firm Transmission Service Allowed: Yes Non-Consequential Load Loss Allowed: Yes With this change, Requirement R4.6 should be revised as follows: “If the analysis concludes there is Cascading caused by the occurrence of **Table 1 planning events P8**, a Corrective Action Plan shall be developed…..”

Likes 0	
Dislikes 0	

Response

Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	

We do not agree with the addition of Requirement 4, Part 4.6. We believe this addition contradicts with the basic design, planning and operation criteria of the BES, and exceeds the overarching objectives of achieving an adequate level of reliability.

The intent of assessing extreme events is to get a feel of how the system would perform under such conditions. Where possible, actions could be speculated or designed to mitigate the adverse impact, as already mandated in Part 4.5 of the existing TPL-001-4 standard. To go so far as requiring corrective action plans (CAP) to prevent or reduce the occurrence (such as by duplicating the non-redundant component) goes beyond the basic criteria for the design, planning and operation of the BES. Simply put, it goes beyond the adequate level of reliability. It might be fairly safe to say that quite a few entities will fail the extreme event testing under certain anticipated conditions for which the BES is not designed to withstand. Hence the existing requirement to evaluate possible actions to reduce the likelihood or mitigate the consequences of the event is appropriate, but to develop and implement CAPs for events (e) to (h) in

Footnote 13 will incur in significant cost over and above what's needed to meet the basic criteria. This is philosophically, and in principle, a non-starter. We respectfully request the drafting team not to add this part. However, if the SDT wants to proceed with its proposed approach the following needs to be clarified: This requirement creates ambiguity in studying events. Though the standard requires studying three phase faults, there is no indication about the fault location which influences whether cascading will occur. Generally in the planning studies the faults are applied on the buses since they produce more severe system impacts. When the "component failure of a Protection System" is considered and studied, a bus fault or a close in fault may still be cleared remotely by the back up protections (remote 21 timed, 51, 51N etc.) and Cascading may not occur. When the fault location is moved along the circuits there may be locations, where the fault will remain uncleared, since the remote back up protection systems may not be able to detect the fault, creating conditions for cascading to occur. Planning Engineers are familiar with the protection systems' behavior when they operate as expected. In case the intent of the standard is to study faults at any location (e.g. away from a substation bus) on circuits protected by a nonredundant protection system , then the planning assessment will require additional info from protection system owners (e.g. the performance of the remote backup distance elements required to clear faults while the local protection systems experience single component failure; this is not presently documented for all fault locations that potentially can cause cascading). If this is the intent of the requirement, then the standard should include specific requirements for protection system owners to provide necessary data to the planners.	
Likes 0	
Dislikes 0	
Response	
faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Douglas Webb - Great Plains Energy - Kansas City Power and Light Co. - 1,3,5,6 - SPP RE

Answer	Yes
Document Name	
Comment	

KCP&L agrees with the content but sees an opportunity to improve clarity by making the specific extreme event a separate category of contingency.

A Corrective Action Plan (CAP) is required only in the case of the described specific extreme event identified in the question as "a subset of Table 1 extreme events." Making a separate contingency category sets it apart and highlights the CAP requirement.

We believe, in this instance, there is value in emphasizing the required response of completing a CAP in the event of the described extreme event.

Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer	Yes
Document Name	
Comment	

The SPP Standards Review Group suggests that the drafting team review sections 2F–2H be applicable to EHV level facilities. For example, the new stability extreme event in table 1, 2F, should be revised to state, 3Ø fault on Extra High Voltage (EHV) level Transmission circuit with failure of a non-redundant component of a Protection System13 resulting in Delayed Fault Clearing.

Likes 0	
Dislikes 0	
Response	

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
The SRC agrees with the proposed addition of Part 4.6.	
Likes 0	
Dislikes 0	
Response	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	
Comment	
While less probable than single-phase-to-ground faults, three-phase faults are single events and single-phase-to-ground faults will often evolve into three-phase faults under severe delayed clearing scenarios such as a P5 contingency. Therefore, to the extent these extreme events cause cascading, it may be prudent to require a corrective action plan. However, consideration should be given to handling this as a Table 1 P8 contingency where the performance requirement is simply no cascading or loss of stability. This is a cleaner way to address this issue because it does not introduce additional performance requirements for the extreme event category.	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kayleigh Wilkerson - Lincoln Electric System - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Payam Farahbakhsh - Hydro One Networks, Inc. - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Chris Scanlon - Exelon - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shelby Wade - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC,RF, Group Name PPL - Louisville Gas and Electric Co.	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Hasan Matin - United Illuminating Co. - 1,3 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 1,3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Robert Ganley - Long Island Power Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell – Tacoma Public Utilities (Tacoma, WA) - 3	
Answer	No
Document Name	
Comment	
Tacoma Power disagrees with the concept of requiring CAPs for extreme events. If events are critical enough to need a CAP, they should be listed as required contingencies. Please see our comments to question 2 with regard to which events at which voltage levels should have CAPs.	
Likes 0	
Dislikes 0	
Response	

5. Do you agree with the drafting team’s approach which doesn’t add additional applicable entities to the applicability of the standard? (e.g. RC, Transmission Operator (TO), Generator Operator (GO), Distribution Provider (DP))	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
Due to referencing RC in the proposed requirement 1.1.2, it should be added as an applicable entity if the proposal is adopted, however, the RC should not have any involvement in the near-term planning timeframe. Also, TO needs to be added as an applicable entity if the three phase fault is moved along the circuit to determine the location for cascading as explained in Q4 above.	
Likes 0	
Dislikes 0	
Response	
Robert Ganley - Long Island Power Authority - 1	
Answer	No
Document Name	
Comment	
As mentioned in our comments to Question #1, , we would suggest the SDT investigate the possibility of taking a step back and altering proposed requirement 1.1.2 to make it applicable to a TOP and also a TP. The TOP may be in the best position to be aware of known / planned outages in the near term planning horizon, and to be able to identify such outages to the TP. As stated in the rationale, the goal is not to consider hypothetical outages. The TOP may be in the best position to identify known / planned outages, prioritize them in terms of reliability impact, and then them provide to the TP for analysis in the annual near term planning horizon planning assessment. If the TOP is not the right applicable entity to share this requirement with the TP , then perhaps the RC is the correct entity.	

Consistent with this suggestion, we would note that the ERO Enterprise-Endorsed Implementation Guidance for TPL-001-4 mentions, for Req #1.1.2, the practice of obtaining “known outages information from applicable (in its area or in an adjacent area) Reliability Coordinators (RCs), Generator Operators (GOPs), or Transmission Operators (TOPs).”	
Likes 0	
Dislikes 0	
Response	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6	
Answer	No
Document Name	
Comment	
If the SDT does not accept our comment to clarify and revise R1.1.2 and R2.1.3, then then the applicability of TPL-001 must be expanded to include the RC, to ensure the RC “consults” with the TP. TO and GO that own Protection Systems should be added to applicability, so that those entities are required to provide the necessary Protection System information to the Transmission Planner so the TP can perform the Planning Analysis.	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	No
Document Name	
Comment	
RC should become an applicable entity.	

Likes 0	
Dislikes 0	
Response	
John Babik - JEA - 1,3,5	
Answer	No
Document Name	
Comment	
For meeting the compliance for Requirement R1 – part 1.1 – subpart 1.1.2 and for Requirement R2 – part 2.1 – subpart 2.1.3, the cooperation of the RC is required by PCs and TPs. But RC is NOT under compliance requirement for this action since the standard is NOT applicable to them. Hence, inaction from RC can expose PCs and TPs to possible violation with these sub-requirements. Instead **IRO-017 Outage Coordination** standard is a better venue to address FERC's concern from Paragraph 40 and **TPL-001** standard should be maintained solely as a *true* Transmission Planning Standard. **Suggestion**: Address this in a future revision of IRO-017.	
Likes 0	
Dislikes 0	
Response	
larry brusseau - Corn Belt Power Cooperative - 1	
Answer	No
Document Name	
Comment	
Corn Belt agrees with the SPP Standards Review Group proposal that a standard applicable to the Reliability Coordinator (RC) address RC requirements should be considered. Potentially, it could be added to NERC Stanadard IRO-017.	

Corn Belt agrees with the SPP Standards Review Group suggestion that the Transmission Owners (TOs) and Generator Owners (GOs) should be added to the applicability section of the standard and have requirements to respond to TP/PC requests for information to help the PC/TP develop Corretive Action Plans (CAPs).	
Likes 0	
Dislikes 0	
Response	
Oliver Burke - Entergy - Entergy Services, Inc. - 1,5	
Answer	No
Document Name	
Comment	
In addition to response to question 1 regarding inclusion of RC, GO/GOP should also be included. If the TP identifies a Corrective Action Plan which involves adding redundancy to generator protection relays, they cannot require that the GO implement that plan.	
Likes 0	
Dislikes 0	
Response	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
The standard should not involve the RC. However, the standard should direct the PC or TP to consult with the TO to determine whether or not specific facilities are applicable to P5 contingencies based on single points of failure and how the remote backup protection would respond for a P5 contingency in terms of sequence of events, clearing times, and additional facilities tripped, and reclosing. Perhaps the TO should be an applicable entity responsible for	

defining and providing the P5 contingency definitions to the PC and TP. Protection system are complex and often vary across a system, so protection engineers should be involved in defining the details of P5 contingencies.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no ISO-NE, NYISO and NextEra	
Answer	No
Document Name	
Comment	
If the SDT does not accept our comment to clarify and revise R1.1.2 and R2.1.3, then then the applicability of TPL-001 must be expanded to include the RC, to ensure the RC "consults" with the TP. TO and GO that own Protection Systems should be added to applicability, so that those entities are required to provide the necessary Protection System information to the Transmission Planner so the TP can perform the Planning Analysis.	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
Depending on how R1, Part 1.1.2 is revised, the RC may have an obligation to provide consultation to the TP/PC, or otherwise the TP/PC can be assessed non-compliant if the RC does not respond to the TP/PC's requests. Therefore the RC should be a responsible entity.	

Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Duke Energy requests further clarification from the SDT on the rationale to leave the RC out of the applicability of this standard. If TPL-001-5 R1.1.2 remains as is in the proposed standard, then the RC must appear in the Applicability portion of the standard. The RC has an explicit role to determine what outages must be studied, not a role as a consultant. Outages are not singular isolated events. Outages occur in combinations and under varying system conditions. The RC, not the transmission planner, has the more appropriate background knowledge and skill set to make the best determination on what to study. Neither the proposed TPL-001-5, nor the existing IRO-017 make clear the RC has lead responsibility that it should for ensuring proper evaluation and coordination of outages has been performed. We understand that it is inferred that IRO-017 covers this action from the RC. Even there the responsibility is only on the PC/TP to jointly develop solutions with its RC for identified issues or conflicts. No explicit language in IRO-017 exists that requires the RC to provide the outage that must be studied to the PC/TP. We reiterate that actions requiring operational personel to perform work should rest in an operational standard.	
Likes 0	
Dislikes 0	
Response	
Jameson Thornton - Pacific Gas and Electric Company - 1 - WECC	
Answer	No
Document Name	
Comment	

Due to the emphasis on planned maintenance outages it is important that the parties which will provide the known outage information to the Planning Coordinator and Transmission Planner be assigned to the Reliability Standard to ensure that information is provided in a timely manner. This may include the Reliability Coordinator, Tranmission Operator, Transmission Owner, Generator Owner or a combination of those functional entities. Additionally the Transmission Owner should be included for purposes of single point of failure due to non-redundant Protection System elements. Finally, Distribution Provider should be added anywhere Load Serving Entity is mentioned.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
The proposed “consultation” approach, as currently drafted, raises a number of issues. Most critically, the proposed standard imposes no compliance obligations on the RC, but permits the TP and PC to exempt certain projects by “consulting” with the RC, which implies action by the RC. As such, a PC or TP could potentially omit certain P1 contingencies from their annual Planning Assessments and then provide that information to the RC. The TP and PC do not have to obtain the RC’s consent or approval to the proposed omissions. Thus, merely providing this information arguably constitutes a “consultation” under the Standard. The RC in turn is under no affirmative obligation to act on that request. As a result, P1 contingencies could not be modeled and may not have been fully considered by the RC, but the resulting Planning Assessment would still comply with the standard. Given this fact, the proposed extension of a “consultation” process to all planned outages raises a number of issues and is over broad. Texas RE suggests the SDT clarify what constitutes a valid consultation and should at a minimum limit the application of a “consultation” exemption to planned outages with a duration of less than six months.	
Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
The SPP Standards Review Group proposes that a standard applicable to the Reliability Coordinator (RC) address RC requirements should be considered. Potentially, it could be added to NERC Stanadard IRO-017. The SPP Standards Review Group suggests that the Transmission Owners (TOs) and Generator Owners (GOs) should be added to the applicability section of the standard and have requirements to respond to TP/PC requests for information to help the PC/TP develop Corretive Action Plans (CAPs).	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	No
Document Name	
Comment	
For meeting the compliance for Requirement R1 – part 1.1 – subpart 1.1.2 and for Requirement R2 – part 2.1 – subpart 2.1.3, the cooperation of the RC is required by PCs and TPs. But RC is NOT under compliance requirement for this action since the standard is NOT applicable to them. Hence, inaction from RC can expose PCs and TPs to possible violation with these sub-requirements. Instead **IRO-017 Outage Coordination** standard is a better venue to address FERC's concern from Paragraph 40 and **TPL-001** standard should be maintained solely as a *true* Transmission Planning Standard. Suggestion: Address this in a future revision of IRO-017.	
Likes 0	

Dislikes 0	
Response	
Michael Haff - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	No
Document Name	
Comment	
Seminole endorses the comments submitted on this Project by JEA.	
Likes 0	
Dislikes 0	
Response	
Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	
Answer	No
Document Name	
Comment	
Depending on how R1, Part 1.1.2 and Part 2.1.3 are revised, the RC may have an obligation to provide consultation to the TP/PC, or otherwise the TP/PC can be assessed non-compliant with the part if the RC does not respond to the TP/PC's requests.	
Likes 0	
Dislikes 0	
Response	

Brandon McCormick - Florida Municipal Power Agency - 3,4,5 - FRCC	
Answer	No
Document Name	
Comment	
The RC should be included. Omitting the RC removes any compliance responisiblity for the RC and places it soley on the PC and TP.	
Likes 0	
Dislikes 0	
Response	

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
If the standard is calling for PC/TP collaboration/coordination, etc. with other functional entities, applicability of the TPL-001-5 standard should also apply to those other entities (e.g. RC) so they have a vested interest in collaborating with the PC/TP.	
Likes 0	
Dislikes 0	
Response	

Bridget Silvia - Sempra - San Diego Gas and Electric - 1,3,5	
Answer	Yes
Document Name	

Comment	
SDG&E agrees with the SDT, but SDG&E is concerned that the role the RC, TOs, GOs and DPs is not well defined with respect to TPL-001. If the SDT keeps the reference to the Reliability Coordinator in section 1.1.2., then the Reliability Coodinator should be added as an applicable entity.	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
If the proposed changes to Requirement 1, Part 1.1.2 are adopted, RCs should be added to the applicability of the standard, because PCs/TPs would need to rely on the cooperation of RCs. As indicated in response to question 1, we do not agree with the proposed changes to R1.1.2.	
Likes 0	
Dislikes 0	
Response	
Shawn Abrams - Santee Cooper - 1,3,5,6, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	

Comments: We recommended removing the Reliability Coordinator from having a compliance obligtation with this standard. Therefore, we agree that they should NOT be added as an Applicable Entity. This standard should remain a Planning Standard and should not require involvement from the Reliability Coordinator.	
Likes 0	
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
The current proposed standard has requirements that are applicable only to the PC and TP; therefore, it makes sense to have the standard itself applicable only to PCs and TPs. It doesn't make sense to do it any other way. Therefore, the standard needs to remove implied requirements for the RC to consult with the PC/TP.	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	

The question is inconsistent with commonly used abbreviations for functional entities. What functional entities are the SDT referencing and did not include in the applicability of this standard? Is the SDT attempting to refer to Transmission Owners (TO) versus Transmission Operators (TOP) and Generator Owners (GO) versus Generator Operators (GOP)? Nonetheless, we believe the applicability section should be reflective of only those entities that are required to maintain system models and conduct analytical studies identified within the standard.

Likes 0	
Dislikes 0	

Response
Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company

Answer	Yes
Document Name	

Comment
Its seems strange to bring the RC into the planning world when the Standard does not apply to that function, and the RC is not a responsible entity. To eliminate this, including potentially adding the RC as a responsible entity in this standard (R1), remove the RC language as proposed above in the response to Question 1. But if the RC is included, our recommendation would be for Requirement 1, Part 1.1.2 to state "request known outages from the RC to be considered for analysis."

Likes 0	
Dislikes 0	

Response
Douglas Webb - Great Plains Energy - Kansas City Power and Light Co. - 1,3,5,6 - SPP RE

Answer	Yes
Document Name	

Comment

KCP&L agrees with the drafting team's approach.	
Likes 0	
Dislikes 0	
Response	
Long Duong - Public Utility District No. 1 of Snohomish County - 1,4,5	
Answer	Yes
Document Name	
Comment	
Yes, SNPD agrees with the Drafting Team's approach which does not add additional applicable entities to the applicability of the standard.	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 1,3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1,3,5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hasan Matin - United Illuminating Co. - 1,3 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shelby Wade - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC,RF, Group Name PPL - Louisville Gas and Electric Co.	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeff Powell - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Chris Scanlon - Exelon - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dori Quam - NorthWestern Energy - 1,3 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Angela Gaines - Portland General Electric Co. - 1,3,5,6, Group Name PGE - Group 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Deborah VanDeventer - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 1,3,5,6

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Lauren Price - American Transmission Company, LLC - 1

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

John Pearson - ISO New England, Inc. - 2 - NPCC

Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Darnez Gresham - Berkshire Hathaway - PacifiCorp - 6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 1,3,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Payam Farahbakhsh - Hydro One Networks, Inc. - 1,3	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey Watkins - Berkshire Hathaway - NV Energy - 6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kayleigh Wilkerson - Lincoln Electric System - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Eric Shaw - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1,5,6, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1,3,5,6, Group Name AECI & Member G&Ts	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	
Document Name	
Comment	
If the drafting team moves forward with the proposed change to move away from the 6 month outage duration, the list of applicable entities should be expanded to include RC and TO (Transmission Owner).	
Likes 0	
Dislikes 0	
Response	

John Merrell – Tacoma Public Utilities (Tacoma, WA) - 3	
Answer	Yes
Document Name	
Comment	
Tacoma Power agrees with the drafting team, provided that the Reliability Coordinator's role under Requirement R1, Part 1.1.2, is only advisory.	

Likes 0	
Dislikes 0	
Response	

6. Do you agree with the 36 month implementation period to address All Requirements except for Requirement R4, Part 4.6, and Requirement 2, Part 2.7 associated with P5 due to Footnote 13 bullets 2, 3 and 4, as well as the definitions?	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
We don’t agree that these changes are required to perform the assessment. We do agree that a complete refurbishment of the standard should be completed, with NERC holding technical discussions in an open forum as was done with other standards.	
Likes 0	
Dislikes 0	
Response	
Gary Trent - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	No
Document Name	
Comment	
Plans and budgets are typically evaluated for at least a 5 year window. Adding requirements that could afect these plans should allow a similar length of time to implement. The minimum implementation perios should be 60 months.	
Likes 0	
Dislikes 0	
Response	

Mark Riley - Associated Electric Cooperative, Inc. - 1,3,5,6, Group Name AECI & Member G&Ts	
Answer	No
Document Name	
Comment	
AECI disagrees with the proposed requirements, and therefore disagrees with the 36 month implementation plan.	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Oncor Electric Delivery - 1 - Texas RE	
Answer	No
Document Name	
Comment	
The 36 month implementation period is too short of a time to address all requirements except Requirement R4, Part 4.6, and Requirement 2, Part 2.7 associated with P5 due to Footnote 13 bullets 2, 3 and 4, as well as the definitions. The 60 month implementation plan for everything doesn't create any confusion on which requirements need to be implemented and gives the planning engineer(s) more time to make sure all requirements are addressed in their annual planning assessment.	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	

Comment	
Based on our comments requesting additional clarity be provided on redundancy and its levels, as well as what is meant by "single communication system", we cannot agree with the 36 month implementation period, until said clarification is provided. It is not possible to know if 36 months, or 60 months is adequate unless the scope of work is clearly understood by industry stakeholders. Once additional clarity is provided, expectations will be clearer, and level/scope of work will be more easily determined.	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 1,3,6	
Answer	No
Document Name	
Comment	
By providing oly 36 months to accomplish these requirements, it would force TOs to essentially perform simulations at all locations, assuming that relay redundancy does not exist anywhere, rather than determine first where relay redundancy does not exist and limit the scope of transient stability simulations to those locations.	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	

SCL disagrees with the proposed requirements, and therefore disagrees with the 36 month implementation plan.	
Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
This question is not applicable. NIPSCO does agree with the proposed changes in the question.	
Likes 0	
Dislikes 0	
Response	
faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Long Duong - Public Utility District No. 1 of Snohomish County - 1,4,5	
Answer	Yes
Document Name	
Comment	

SNPD is however, somewhat concerned with the 36 month implementation period to address **All Requirements** except for Requirement R4, Part 4.6, and Requirement 2, Part 2.7 associated with P5, because our budget approval process may require 1-2 years and the construction period may need 5-7 years. It would be more practical for the Drafting Team to suggest an implementation plan with the following items:

- Provide Project Goals and Objectives
- Provide a List of Tasks, and Tentative Schedules

Likes 0	
Dislikes 0	
Response	
Michael Haff - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	Yes
Document Name	
Comment	

Seminole endorses the comments submitted on this Project by JEA.

Likes 0	
Dislikes 0	
Response	

Douglas Webb - Great Plains Energy - Kansas City Power and Light Co. - 1,3,5,6 - SPP RE	
Answer	Yes
Document Name	
Comment	
KCP&L agrees with the 36-month assessment period.	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1,5,6, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	
However, the implementation plan should clearly apply to the "raise-the-bar" portions of the revision.	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1 - SERC	
Answer	Yes
Document Name	

Comment	
The implementation period and associated implementation plan are hard to follow. This is an industry wide issue, not just directed this standard. Suggested change would be to put actual dates in place of relate dates identified before the standard is approved. We have no problem with the 36 months as listed.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no ISO-NE, NYISO and NextEra	
Answer	Yes
Document Name	
Comment	
Agreed	
Likes 0	
Dislikes 0	
Response	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Agreement to the implementation period does not convey agreement with the content of the proposed changes to the standard.	

Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Yes. As long as the implementation plan refers to the development of required CAPs, not the placing the required CAPs in service.	
Likes 0	
Dislikes 0	
Response	
larry brusseau - Corn Belt Power Cooperative - 1	
Answer	Yes
Document Name	
Comment	
see attached file in question 1	
Likes 0	
Dislikes 0	
Response	

Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Yes. As long as the implementation plan refers to the development of required CAPs, not the placing the required CAPs in service.	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Florida Municipal Power Agency - 3,4,5 - FRCC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jameson Thornton - Pacific Gas and Electric Company - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kayleigh Wilkerson - Lincoln Electric System - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey Watkins - Berkshire Hathaway - NV Energy - 6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Payam Farahbakhsh - Hydro One Networks, Inc. - 1,3	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Darnez Gresham - Berkshire Hathaway - PacifiCorp - 6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shawn Abrams - Santee Cooper - 1,3,5,6, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

John Pearson - ISO New England, Inc. - 2 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Oliver Burke - Entergy - Entergy Services, Inc. - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1,3,5,6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Deborah VanDeventer - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Angela Gaines - Portland General Electric Co. - 1,3,5,6, Group Name PGE - Group 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

John Babik - JEA - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeff Powell - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shelby Wade - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC,RF, Group Name PPL - Louisville Gas and Electric Co.	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hasan Matin - United Illuminating Co. - 1,3 - NPCC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 1,3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Robert Ganley - Long Island Power Authority - 1

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Leonard Kula - Independent Electricity System Operator - 2

Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	

Document Name	
Comment	
Texas RE requests the SDT provide technical basis supporting a 36 month implementation period.	
Likes 0	
Dislikes 0	
Response	
John Merrell – Tacoma Public Utilities (Tacoma, WA) - 3	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

7. Do you agree with the 60 month implementation plan for Requirement 4, Part 4.6 and Requirement 2, Part 2.7 associated with P5 due to Footnote 13 bullets 2, 3 and 4?

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No

Document Name	
Comment	
BPA does not support the requirement for Corrective Action Plans in 4.6, BPA believes it is not economically justifiable to require Corrective Action Plans for low probability extreme events like these. Instead, an effort to minimize the likelihood of cascading should be considered, if studies indicate there is the potential for cascading on critical parts of the system. If Corrective Action Plans are going to be required, BPA agrees that the 60-month implementation plan is appropriate.	
Likes 0	
Dislikes 0	
Response	
Jeff Powell - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
TVA agrees with having 60 months for the development of the corrective action plan. However, we do not agree that a corrective action plan should be required for Requirement 4, Part 4.6.	
Likes 0	
Dislikes 0	
Response	
John Babik - JEA - 1,3,5	
Answer	No
Document Name	

Comment	
The new language under Requirement R4, Part 4.6 should be deleted all together. It goes far beyond what the conclusion from the analysis from Order No. 754 recommended and will cost the industry a very significant amount of time and money for implementation for a comparatively insignificant improvement in the reliability. Requirement R4, Part 4.5 already addresses this cascading issue for extreme events in the Commission approved and currently enforceable TPL-001-4 standard and should be left as-is. We agree that for the Requirement 2, Part 2.7 associated with P5 due to Footnote 13 bullets 2, 3 and 4 events, the system still needs to perform reliably and without any planning criteria violation. However, no operational workaround can be performed for any newly identified violation due to this suggested/clarified language for Footnote 13 and capital improvement projects will be the “only” corrective action plans which will require a significant time and effort for coordination among PCs, TPs and the Facility owners and operators (TO/ TOP/ GO/ GOP). In addition, the installation/ implementation of such Corrective Action Plans may cost the industry tens of billions of dollars with significant construction effort spanning 10-20 years. Hence a mere 60 months (5 years) for meeting Requirement 2, Part 2.7 associated with P5 due to Footnote 13 bullets 2, 3 and 4 implementation and compliance is not adequate. The industry needs to be surveyed again to see the outcome from the studies with the modified/clarified language in 5 years (after 36 months for TPL-001-5 effective date + 24 months to develop corrective action plan) to have a more realistic implementation schedule for the remedies (Corrective Action Plans) for Part 2.7. **Suggestion**: Requirement 4, Part 4.6 is not needed since Requirement R4, Part 4.5 already addresses it. Regarding Requirement 2, Part 2.7, an additional industry survey will be needed to determine a reasonable and appropriate timeline to implement the Corrective Action Plans just for the newly identified shortcomings for P5 events with the proposed/modified Footnote 13.	
Likes 0	
Dislikes 0	
Response	
larry brusseau - Corn Belt Power Cooperative - 1	
Answer	No
Document Name	
Comment	
We (utilities) probably already know that we cannot meet the 60 month implementation period. Capital improvements can not be determined and implemented in a 60 month time period. Forced compliance to 60 months would require undesirable mitigations such as system protection adjustments that	

might reduce system security, misoperations due to changes in protection systems that result in non-standard configurations and changes to maintenance practices due to non-standard application of protection systems. There is a concern that utilities will not be able to meet the 60 month implementation plan in a reliabile manner. Unlike other potential areas identified in Planning Studies where the system may not meet the System Performance Requirements outlined in Table 1, other temporary reliable solutions, such as the use of Operating Procedures, are available that can be implemented until a long term solution (capital project) is completed. In many instances the only way to fully mitigate impacts resulting from "failure of a non-redundant component of a Protection System" event is to add redundancy. If this cannot be achieved in 60 months utilities may be forced to make undesirable system protection adjustments that could result in a higher rate of misoperations, reduction of system security, and reduced reliability until redundancy can be added. This should not be interpreted as utlities ignoring the importance of adding redundancy at critical points on the system, but implementation should be done on a cost/benefit (risk assessment) basis that takes into consideration the resources individual utilities have to adequately address areas of concerns resulting fromorm single points of failure. In other words, the timing requirement of the implementation plan should not be so prescriptive that it leads to greater reliability risks than the conerns associated with the potential consequences of a single point of failure event.	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	No
Document Name	
Comment	
There is a concern that utilities will not be able to meet the 60 month implementation plan in a reliabile manner. Unlike other potential areas identified in Planning Studies where the system may not meet the System Performance Requirements outlined in Table 1, other temporary reliable solutions, such as the use of Operating Procedures, are available that can be implemented until a long term solution (capital project) is completed. In many instances the only way to fully mitigate impacts resulting from "failure of a non-redundant component of a Protection System" event is to add redundancy. If this cannot be achieved in 60 months utilities may be forced to make undesirable system protection adjustments that could result in a higher rate of misoperations, reduction of system security, and reduced reliability until redundancy can be added. This should not be interpreted as utlities ignoring the importance of adding redundancy at critical points on the system, but implementation should be done on a cost/benefit (risk assessment) basis that takes into consideration the resources individual utilities have to adequately address areas of concerns resulting form single points of failure. In other words, the timing requirement of	

the implementation plan should not be so prescriptive that it leads to greater reliability risks than the conerns associated with the potential consequences of a single point of failure event.

Likes 0	
Dislikes 0	
Response	
Angela Gaines - Portland General Electric Co. - 1,3,5,6, Group Name PGE - Group 1	
Answer	No
Document Name	
Comment	
The scale of the Corrective Action Plans is unknown, and the coordination of capital projects may require a longer duration to effectively manage outage risks with other planned projects could exceed 60 months.	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	
SCL disagrees with the proposed requirements, and therefore disagrees with the 60 month implementation plan.	
Likes 0	

Dislikes 0	
Response	
Shawn Abrams - Santee Cooper - 1,3,5,6, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	
Comments: The new language under Requirement R4, Part 4.6 should be deleted all together. It goes far beyond what the conclusion from the analysis from Order No. 754 recommended and will cost the industry a very significant amount of time and money for implementation for a comparatively insignificant improvement in the reliability. Requirement R4, Part 4.5 already addresses this cascading issue for extreme events in the Commission approved and currently enforceable TPL-001-4 standard and should be left as-is. Recomment removing Requirement 4 Part 4.6 since Part 4.5 already addressesit.	
Likes 0	
Dislikes 0	
Response	
Darnez Gresham - Berkshire Hathaway - PacifiCorp - 6 - WECC	
Answer	No
Document Name	
Comment	
Developing a mitigation plan and getting it in-service can be very challenging for utilities based on their budgetary requirements.	
Likes 0	
Dislikes 0	

Response	
David Jendras - Ameren - Ameren Services - 1,3,6	
Answer	No
Document Name	
Comment	
We believe that a phased approach should be taken to address the concerns for single point of failure. We do not believe that all transmission facilities are of equal value or pose an equal risk to the system. We believe that the risk is generally related to system voltage, and the highest voltage facilities need to be addressed first. Further, we recognize that there are many more lower voltage facilities with non-redundant protection systems that need to be addressed, and these upgrades will likely require the expansion or addition of control buildings to house the additional protection system components.	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
See response to question 6.	
Likes 0	
Dislikes 0	
Response	

Jameson Thornton - Pacific Gas and Electric Company - 1 - WECC	
Answer	No
Document Name	
Comment	
a 60 month time frame may not be achievable depending on the scope of issues discovered. PG&E recommends that this be determined by the Transmission Owner in coordination with the Transmisison Planner and Planning Coordinator, or 120 months.	
Likes 0	
Dislikes 0	
Response	

Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	No
Document Name	
Comment	
The new language under Requirement R4, Part 4.6 should be deleted all together. It goes far beyond what the conclusion from the analysis from Order No. 754 recommended and will cost the industry a very significant amount of time and money for implementation for a comparatively insignificant improvement in the reliability. Requirement R4, Part 4.5 already addresses this cascading issue for extreme events in the Commission approved and currently enforceable TPL-001-4 standard and should be left as-is. We agree that for the Requirement 2, Part 2.7 associated with P5 due to Footnote 13 bullets 2, 3 and 4 events, the system still needs to perform reliably and without any planning criteria violation. However, no operational workaround can be performed for any newly identified violation due to this suggested/clarified language for Footnote 13 and capital improvement projects will be the “only” corrective action plans which will require a significant time and effort for coordination among PCs, TPs and the Facility owners and operators (TO/ TOP/ GO/ GOP). In addition, the installation/ implementation of such Corrective Action Plans may cost the industry tens of billions of dollars with significant construction effort spanning 10-20 years. Hence a mere 60 months (5 years) for meeting Requirement 2, Part 2.7 associated with P5 due to Footnote 13 bullets 2, 3 and 4 implementation and compliance is not adequate. The industry needs to be surveyed again to see the outcome from the studies with the modified/clarified language in 5 years (after 36 months for TPL-001-5 effective date + 24 months to develop corrective action plan) to have a more realistic implementation schedule for the remedies (Corrective Action Plans) for Part 2.7.	

Suggestion: Requirement 4, Part 4.6 is not needed since Requirement R4, Part 4.5 already addresses it. Regarding Requirement 2, Part 2.7, an additional industry survey will be needed to determine a reasonable and appropriate timeline to implement the Corrective Action Plans just for the newly identified shortcomings for P5 events with the proposed/modified Footnote 13.	
Likes 0	
Dislikes 0	
Response	
Joe Tarantino - Sacramento Municipal Utility District - 1,3,4,5,6 - WECC	
Answer	No
Document Name	
Comment	
<span style="font-family: calibri,sans-serif; font-size: 12pt; mso-ascii-theme-font: minor-latin; mso-ansi-language: EN-US;" mso-hansi-theme-font:minor-latin"="" mso-fareast-language:en-us;="" roman";="" new="" mso-fareast-font-family:"times="" mso-bidi-language:ar-sa;="" times="">SMUD does not agree with the need for Part 4.6, as such cannot agree with an implementation plan for this requirement. SMUD does agree with the 60-month implementation date for the other requirements listed.	
Likes 0	
Dislikes 0	
Response	
Michael Haff - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	No
Document Name	
Comment	

Seminole endorses the comments submitted on this Project by JEA.	
Likes 0	
Dislikes 0	
Response	
Gary Trent - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	No
Document Name	
Comment	
As stated in question 6, the minimum time for implementation should be 60 months to account for existing plans and budgets. This should be an additional 24-36 months beyond the implementation period for the other requirements. Therefore, the implementation period should be between 84 and 96 months at a minimum.	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Florida Municipal Power Agency - 3,4,5 - FRCC	
Answer	No
Document Name	
Comment	
Comments: Requirement 4, part 4.6, should be deleted. This new requirement goes way beyond	

what was recommended by Order No. 754 and has the possibility to cause undue financial burden to industry without a corresponding benefit to reliability. With regards to Requirement 2, Part 2.7, 60 months for implementation is not sufficient. The possibility of large capital expenditure due to Corrective Action Plans as well as the associated construction timelines makes a 60 month implementation difficult to comply with. A suggestion would be to perform a survey to see what corrective action plans are required after industry has had time to do evaluations and then establish an implementaion timeline.	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Yes. As long as the implementation plan refers to the development of required CAPs, not the placing the required CAPs in service.	
Likes 0	
Dislikes 0	
Response	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Agreement to the implementation period does not convey agreement with the content of the proposed changes to the standard.	
Likes 0	
Dislikes 0	

Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no ISO-NE, NYISO and NextEra	
Answer	Yes
Document Name	
Comment	
Agreed.	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1 - SERC	
Answer	Yes
Document Name	
Comment	
The implementation period and associated implementation plan are hard to follow. This is an industry wide issue, not just directed this standard. Suggested change would be to put actual dates in place of relate dates identified before the standard is approved. We have no problem with the 60 months as listed.	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1,5,6, Group Name LCRA Compliance	

Answer	Yes
Document Name	
Comment	
However, the implementation plan should clearly apply to the "raise-the-bar" portions of the revision.	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Great Plains Energy - Kansas City Power and Light Co. - 1,3,5,6 - SPP RE	
Answer	Yes
Document Name	
Comment	
KCP&L agrees with the “60-month” implementation plan; however, suggests adding language to clarify what the “60-month” period represents. The question implies there is a distinction in the implementation periods for specific Requirements, allowing 60-months for some and something different for other Requirements. We only can guess that the referenced 60-month period reflects the sum of the 36-month assessment period and the 24-month CAP development period. If that is the case, we suggest not using “60-months” and list the allocated implementation periods for each action—assessments, CAP drafting.	
Likes 0	
Dislikes 0	
Response	
Long Duong - Public Utility District No. 1 of Snohomish County - 1,4,5	

Answer	Yes
Document Name	
Comment	
SNPD does not have simulated events that may cause cascading outages. However, to support the regional and RC efforts with controlling any observable IROL or identified potential IROL events within the WECC region, SNPD shall follow the RC and PC accepted and approved guidelines.	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Ganley - Long Island Power Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 1,3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hasan Matin - United Illuminating Co. - 1,3 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shelby Wade - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC,RF, Group Name PPL - Louisville Gas and Electric Co.	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Chris Scanlon - Exelon - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Deborah VanDeventer - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Mike Smith - Manitoba Hydro - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Oliver Burke - Entergy - Entergy Services, Inc. - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Payam Farahbakhsh - Hydro One Networks, Inc. - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey Watkins - Berkshire Hathaway - NV Energy - 6 - WECC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kayleigh Wilkerson - Lincoln Electric System - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dori Quam - NorthWestern Energy - 1,3 - MRO,WECC	
Answer	
Document Name	
Comment	
Unsure. Some implementation may be longer.	
Likes 0	
Dislikes 0	

Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE requests the SDT provide technical basis supporting a 60 month implementation period.	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1,3,5,6, Group Name AECI & Member G&Ts	
Answer	
Document Name	
Comment	
AECI disagrees with the proposed requirements, and therefore disagrees with the 60 month implementation plan.	
Likes 0	
Dislikes 0	
Response	
John Merrell – Tacoma Public Utilities (Tacoma, WA) - 3	
Answer	No
Document Name	

Comment	
Are corrective action plans required to be developed within 60 months or to be completed within 60 months? Assuming the TP/PC takes most of the 36 months to implement the rest of TPL-001-5, the additional 24 months provides very little time for a TO/GO to actually implement construction projects.	
Likes 0	
Dislikes 0	
Response	

8. Are you aware of any other governing documents that could be in conflict with the current proposal for this draft of the standard?	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no ISO-NE, NYISO and NextEra	
Answer	No
Document Name	
Comment	
Not aware of any.	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
larry brusseau - Corn Belt Power Cooperative - 1	

Answer	No
Document Name	
Comment	
see attached file in question 1	
Likes 0	
Dislikes 0	
Response	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6	
Answer	No
Document Name	
Comment	
Not aware of any.	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Long Duong - Public Utility District No. 1 of Snohomish County - 1,4,5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Florida Municipal Power Agency - 3,4,5 - FRCC	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1,3,5,6, Group Name AECI & Member G&Ts	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Great Plains Energy - Kansas City Power and Light Co. - 1,3,5,6 - SPP RE	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michael Shaw - Lower Colorado River Authority - 1,5,6, Group Name LCRA Compliance	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe Tarantino - Sacramento Municipal Utility District - 1,3,4,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1 - SERC	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Eric Shaw - Oncor Electric Delivery - 1 - Texas RE	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jameson Thornton - Pacific Gas and Electric Company - 1 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kayleigh Wilkerson - Lincoln Electric System - 1,3,5,6

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jeffrey Watkins - Berkshire Hathaway - NV Energy - 6 - WECC

Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 1,3,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Darnez Gresham - Berkshire Hathaway - PacifiCorp - 6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shawn Abrams - Santee Cooper - 1,3,5,6, Group Name Santee Cooper	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2 - NPCC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Oliver Burke - Entergy - Entergy Services, Inc. - 1,5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Deborah VanDeventer - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Angela Gaines - Portland General Electric Co. - 1,3,5,6, Group Name PGE - Group 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dori Quam - NorthWestern Energy - 1,3 - MRO,WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Chris Scanlon - Exelon - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeff Powell - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shelby Wade - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC,RF, Group Name PPL - Louisville Gas and Electric Co.	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hasan Matin - United Illuminating Co. - 1,3 - NPCC	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1,3,5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Aubrey Short - FirstEnergy - FirstEnergy Corporation - 1,3,4	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Haff - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	Yes
Document Name	
Comment	
Seminole endorses the comments submitted on this Project by JEA.	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	

Answer	Yes
Document Name	
Comment	
: Due to the changes incorporated in this proposed TPL standard, Reliability Standard **CIP-014-2 – Physical Security** can be impacted with the outcome. The proposed TPL-001-5 is setting the bar higher than before for the PCs and TPs. This can result in a different scenario for applicable Transmission Facilities for CIP-014-2 as identified by PCs and TPs (CIP-014-2 – section 4. Applicability – 4.1. Functional Entities – 4.1.1 – 4.1.1.3) in accordance with TPL-001-5 analyses.	
Likes 0	
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
While there are no specific documents that stand out as being in conflict with the proposed changes, Peak believes that the notion of separation of responsibilities might be compromised with the proposed changes, specifically, responsibilities between the RC and the PC/TP. Perhaps, in this regard, the proposed changes might conflict with the NERC Functional Model. Some of the proposed revisions might be interpreted to pull RCs into the work for which PCs and TPs are responsible, thus implicitly requiring the RCs to perform duties they otherwise would not perform. While on the surface the proposed revisions may appear to be a good idea to improve communications between operations and planning, Peak believes that there are better ways of achieving that objective without creating implied responsibilities for the RC in the planning horizon, where the RC has no direct responsibility. Peak would support revisions to the requirements that do not create implied responsibilities for the RC in the planning horizon.	
Likes 0	
Dislikes 0	
Response	

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
The proposed changes to sub-requirement 1.1.2 may be in conflict with the standard IRO-017-Outage Coordination, since outage coordination is more of an Operational Planning issue (next day studies up to six months) than a Transmission Planning issue, which covers one to ten year planning horizon.	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
MH believes that the SDT was unable to capture the proposed recommendations in the background document prepared by NERC SPCS and SAMS. A risk based assessment should be used to identify locations of concern rather than making full protection redundancy a bright line requirement. The background document provided a criteria for busses to be evaluated (Table 1.1) and criteria to evaluate the system performance (Table 1.2).	
Likes 0	
Dislikes 0	
Response	
John Babik - JEA - 1,3,5	

Answer	Yes
Document Name	
Comment	
Due to the changes incorporated in this proposed TPL standard, Reliability Standard **CIP-014-2 – Physical Security** can be impacted with the outcome. The proposed TPL-001-5 is setting the bar higher than before for the PCs and TPs. This can result in a different scenario for applicable Transmission Facilities for CIP-014-2 as identified by PCs and TPs (CIP-014-2 – section 4. Applicability – 4.1. Functional Entities – 4.1.1 – 4.1.1.3) in accordance with TPL-001-5 analyses.	
Likes 0	
Dislikes 0	
Response	
Robert Ganley - Long Island Power Authority - 1	
Answer	Yes
Document Name	
Comment	
As previously mentioned in these comments, we noted possible inconsistencies with the following documents: - NERC Glossary definition of “Protection System” - ERO Enterprise-Endorsed Implementation Guidance for TPL-001-4	
Likes 0	
Dislikes 0	
Response	
Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Payam Farahbakhsh - Hydro One Networks, Inc. - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell – Tacoma Public Utilities (Tacoma, WA) - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

9. Do you agree with the teams proposed changes to align the VRF/VSLs for Requirement 4, Part 4.6 with the VRF/VSLs for Requirement 2, Part 2.7?

Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6	
Answer	No

Document Name	
Comment	
No. See Question 4.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA believes that past performance can be a good indicator of future performance. These types of outages have not been an issue in the past. BPA believes that it is not economically justifiable to require corrective action plans for low probability extreme events like these. Instead, BPA believes an effort to minimize the likelihood of cascading should be considered, if studies indicate there is the potential for cascading on critical parts of the system. BPA believes the penalties are too severe for such low probability extreme events.	
Likes 0	
Dislikes 0	
Response	
John Babik - JEA - 1,3,5	
Answer	No
Document Name	Table C.png
Comment	

The new language under Requirement R4, Part 4.6 should be deleted all together. It goes far beyond what the conclusion from the analysis from Order No. 754 recommended and will cost the industry a very significant amount of time and money for implementation for a comparatively insignificant improvement in the reliability. Requirement R4, Part 4.5 already addresses this cascading issue for extreme events in the currently enforceable TPL-001-4 standard and should be left as-is. **Suggestion**: Since Requirement 4, Part 4.6 is not needed, no corresponding VRF/VSL revised language is needed.

Likes 0	
Dislikes 0	
Response	
Angela Gaines - Portland General Electric Co. - 1,3,5,6, Group Name PGE - Group 1	
Answer	No
Document Name	
Comment	
Corrective Action Plans as detailed in Part 2.7 do not explicitly allow for use of Asset Management principals to manage the risk of the likelihood and consequence of an outage.	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	

SCL disagrees with the proposed requirements above, and therefore disagrees with the proposed changes to align requirement 4.6 with requirement 2.7.

Likes 0	
Dislikes 0	

Response

Shawn Abrams - Santee Cooper - 1,3,5,6, Group Name Santee Cooper	
Answer	No
Document Name	

Comment
Comments: The new language under Requirement R4, Part 4.6 should be deleted all together. It goes far beyond what the conclusion from the analysis from Order No. 754 recommended and will cost the industry a significant amount of time and money for implementation for a comparatively insignificant improvement in the reliability. Requirement R4 Part 4.5 already addresses this cascading issue for extreme events in the currently enforceable TPL-001-4 standard and should be left as-is. No corresponding VRF/VSL is needed since this requirement should be removed.

Likes 0	
Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 1,3,6	
Answer	No
Document Name	

Comment

Consistent with our response to Question 4, developing corrective action plans to include redundant relaying for extreme events is inconsistent compared with the existing TPL-001-4 requirements.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no ISO-NE, NYISO and NextEra	
Answer	No
Document Name	
Comment	
Please refer to Question 4 comments.	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
(1) We believe the development a Corrective Action Plan is administrative in nature and constitutes a Lower Violation Risk Factor in the Long-Term Planning Horizon. The proposed requirement to develop a Corrective Action Plan does not have a direct or adverse effect on the electrical state or capability of the BES and does not align with the Medium Violation Risk Factor criteria identified by NERC.	

(2) NERC identifies the criteria for a High VSL as the "performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent." In comparison, NERC identifies the criteria for a Lower VSL as the "performance or product measured almost meets the full intent of the requirement." We propose moving the failure to develop a Corrective Action Plan to the Lower VSL, as the full intent of Requirement R4 focuses more on the performance of Contingency analyses.	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Oncor Electric Delivery - 1 - Texas RE	
Answer	No
Document Name	
Comment	
The Violation Risk Factor (VRF) and Violation Severity Level (VSL) for Requirement 4, Part 4.6 emphasizes a new level of depth for a Corrective Action Plan in the Stability portion of the Planning Assessment. This seems inconsistent with the VRF/VSLs for Requirement 2, Part 2.7 which focus on creating a Corrective Action Plan for a number of actions already implemented by industry standards. See comments #3 and #4.	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	No
Document Name	
Comment	

The new language under Requirement R4, Part 4.6 should be deleted all together. It goes far beyond what the conclusion from the analysis from Order No. 754 recommended and will cost the industry a very significant amount of time and money for implementation for a comparatively insignificant improvement in the reliability. Requirement R4, Part 4.5 already addresses this cascading issue for extreme events in the currently enforceable TPL-001-4 standard and should be left as-is. Suggestion: Since Requirement 4, Part 4.6 is not needed, no corresponding VRF/VSL revised language is needed.	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1 - SERC	
Answer	No
Document Name	
Comment	
For clarification, Part 4.6 is just for developing and not completing a CAP?	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1,5,6, Group Name LCRA Compliance	
Answer	No
Document Name	
Comment	

No, see comments about modifying 4.5 instead of 4.6. The VSL for 4.5 should remain "Lower". Requirements to eliminate non-redundant relay designs should be defined in PRC standards.	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1,3,5,6, Group Name AECI & Member G&Ts	
Answer	No
Document Name	
Comment	
AECI disagrees with the proposed changes to Requirement 4, Part 4.6, and therefore disagrees with the revisions to the VRF/VSLs.	
Likes 0	
Dislikes 0	
Response	
Michael Haff - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	No
Document Name	
Comment	
Seminole endorses the comments submitted on this Project by JEA.	
Likes 0	
Dislikes 0	

Response	
Brandon McCormick - Florida Municipal Power Agency - 3,4,5 - FRCC	
Answer	No
Document Name	
Comment	
R4 4.6 should be deleted entirely for reasons noted above	
Likes 0	
Dislikes 0	
Response	
Jeff Powell - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
larry brusseau - Corn Belt Power Cooperative - 1	
Answer	Yes
Document Name	
Comment	
see attached file in question 1	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
ATC does not comment on VRF/VSLs.	
Likes 0	
Dislikes 0	

Response	
Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
It should not result in a CAP entry and therefore would require no change	
Likes 0	
Dislikes 0	

Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Ganley - Long Island Power Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Aubrey Short - FirstEnergy - FirstEnergy Corporation - 1,3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Hasan Matin - United Illuminating Co. - 1,3 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shelby Wade - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC,RF, Group Name PPL - Louisville Gas and Electric Co.	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Dori Quam - NorthWestern Energy - 1,3 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Oliver Burke - Entergy - Entergy Services, Inc. - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Darnez Gresham - Berkshire Hathaway - PacifiCorp - 6 - WECC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Payam Farahbakhsh - Hydro One Networks, Inc. - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey Watkins - Berkshire Hathaway - NV Energy - 6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kayleigh Wilkerson - Lincoln Electric System - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Great Plains Energy - Kansas City Power and Light Co. - 1,3,5,6 - SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Long Duong - Public Utility District No. 1 of Snohomish County - 1,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

John Merrell – Tacoma Public Utilities (Tacoma, WA) - 3	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

10. Do you have any other general recommendations / considerations for the drafting team?	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	
No further comments at this time.	
Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
These comments were submitted on behalf of Dawn Quick at NIPSCO dquick@nisource.com	
Likes 0	
Dislikes 0	
Response	

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1,3,5,6, Group Name AECI & Member G&Ts	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1,5,6, Group Name LCRA Compliance	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 1,3,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2 - NPCC	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Oliver Burke - Entergy - Entergy Services, Inc. - 1,5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Deborah VanDeventer - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Angela Gaines - Portland General Electric Co. - 1,3,5,6, Group Name PGE - Group 1	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Scanlon - Exelon - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeff Powell - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shelby Wade - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC,RF, Group Name PPL - Louisville Gas and Electric Co.	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hasan Matin - United Illuminating Co. - 1,3 - NPCC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Aubrey Short - FirstEnergy - FirstEnergy Corporation - 1,3,4

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Robert Ganley - Long Island Power Authority - 1

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jamie Monette - Allete - Minnesota Power, Inc. - 1

Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Long Duong - Public Utility District No. 1 of Snohomish County - 1,4,5	
Answer	Yes
Document Name	
Comment	
Order 786 specifically mentions that TPL-001 is intended to analyze the Near-Term Transmission Planning Horizon and requires annual assessments using Year One or Year Two, and Year Five. We agree that 1-, 2-, and 5-year forward looking is the appropriate and intended timeframe to be evaluated by the requirements of TPL-001. Therefore, only outages planned for this timeframe (more than 12-months forward) are appropriate to require analysis as a Standard Requirement of Transmission Planning such as TPL-001. Anything less than 1-year belongs to the Operations timeframe.	
Likes 0	
Dislikes 0	
Response	

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE

Answer	Yes
Document Name	
Comment	

The modified verbiage for Part 2.1.3 includes the phrase “as selected in consultation with the Reliability Coordinator” – this modification is unnecessary and causes confusion. It is not clear why Part 2.1.3 needs to be modified at all. Further, including this phrase in Part 2.1.3 makes it inconsistent with the verbiage in Part 2.4.3

If the standard is calling for PC/TP consultations with other functional entities (RC), applicability of the TPL-001-5 standard should also apply to those other entities so those entities have a vested interest in collaborating with the PC/TP. Otherwise the other entities have no obligation to participate.

Finally, NERC should undertake a complete refurbishment of the standard, with NERC holding technical discussions in an open forum to address all the ambiguities presently left to interpretation.

Likes 0	
Dislikes 0	
Response	

Brandon McCormick - Florida Municipal Power Agency - 3,4,5 - FRCC

Answer	Yes
Document Name	
Comment	

1) Both additions in the stability analysis section (R2.4.3 and R2.4.5) need to reference or somehow incorporate R4.4 and the ability of the PC or TP to identify and simulate only those events that are expected to produce the most severe System Impacts. This allows the PC and TP to maintain some semblance of engineering judgment and avoid conducting an un-bounded number of simulations. 2) The drafting needs to correct the cross reference from R2.7 to R2 part 2.4.3 as the proposed revisions re-number 2.4.3 to 2.4.4.

Thank you again for the efforts of the SDT and we appreciate the opportunity to provide comment. We hope the comments are found to be helpful.	
Likes 0	
Dislikes 0	
Response	
Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	
Answer	Yes
Document Name	
Comment	
In Part 1.2 of section C on page 16, the new language identifying the Measures for which the responsible entity must retain evidence of compliance appears to incorrectly exclude Measure M8. Further, the corresponding changes to IRO-017 relative to R 1.1.2 as recommended in the PC report to the drafting team (excerpt below) should also be pursued: • Use the coordination process developed pursuant to IRO-017-1 Requirement R1 to direct how ALL known scheduled outages are reviewed and the actions that must be taken. The following objectives should be added to R1: · Describe how the review of known scheduled outages by the RC, PC, TO, and TP will be integrated into the Near Term Assessment of the Planning Horizon required by TPL-001-4, and whether and which of these known scheduled outages will be studied in this Assessment. · Describe how emerging challenges and the inability to schedule outages will be communicated from the TO and RC to the TP and PC to be addressed in a future Corrective Action Plan pursuant to TPL-001-4.	
Likes 0	
Dislikes 0	
Response	
Michael Haff - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	Yes

Document Name	
Comment	
Seminole endorses the comments submitted on this Project by JEA.	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Great Plains Energy - Kansas City Power and Light Co. - 1,3,5,6 - SPP RE	
Answer	Yes
Document Name	
Comment	
We have a question: The proposed implementation plan makes reference to, in certain circumstances, carrying over from TPL-001-4 the 84-month exception (our word) period related to Corrective Action Plans including Non-Consequential Load Loss and curtailment of Firm Transmission Service. We are unclear how the 84-month exception will impact, correlate or align with TPL-001-5's proposed 36-month assessment period and the 24-month CAP drafting period?	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1 - SERC	
Answer	Yes

Document Name	
Comment	

In regards to Requirement 5:

There is academic and industry documentation used to define what is “acceptable” related to steady state voltage limits and transient voltage response. The documentation demonstrates negative impact to the transmission system and/or electrical equipment as result of transient voltage remaining below a certain threshold for a certain time-frame, as well as for steady state voltage being either too high or too low.

Georgia Transmission Corporation has not found any academic or industry documentation that suggests that there is a negative impact to either the transmission system or electrical equipment related to steady state voltage deviation.

There is a lack of information to document that steady state post-Contingency deviation (the difference between pre-Contingency steady voltage and post-Contingency steady state voltage) beyond a certain limit has a negative impact on either the transmission system or electrical equipment. Consequently, Transmission Planners and Planning Coordinators will be required to develop a Corrective Action Plan to address system conditions that fall outside of voltage deviation criteria that have no real impact on system reliability. Therefore this voltage deviation criteria should be eliminated.

Likes 0	
Dislikes 0	
Response	

Jesus Sammy Alcaraz - Imperial Irrigation District - 1

Answer	Yes
Document Name	
Comment	

We agree that the data request and analysis after Order No. 754 was a good first step towards addressing the single points of failure in the protection system and the proposed language in TPL-001-5 is an improvement upon that criteria. The added/clarified language in the draft TPL-001-5 for P5 and stability performance extreme events 2e-2h along with footnote 13 will, however, require the PCs and TPs to perform a lot more analyses than was originally performed for Order No. 754 data request.

The criteria for buses to be tested (Table A; reproduced below) under Order No. 754 data request required 4 or more circuits at 200 kV or higher, and, 6 or more circuits between 100 kV to 200 kV. However, the assessment according to the proposed TPL-001-5 requires ALL BES buses; regardless of how many circuits terminate at each BES bus; to be tested. Due to this more in-depth analyses now required, there will definitely be a significant new findings for P5 Planning events for which the performance requirement is more restrictive than the performance measure (Table C; reproduced below) under data request. Before the industry assesses the entire BES (implementation plan: 36 months) followed by the development of the Corrective Action Plans just for P5 events with the proposed Footnote 13 (implementation plan: additional 24 months); it will be very pre-mature at this time to grant 60 months for the Corrective Action Plan implementation. It will be logical to have another survey/data request performed after 60 months from the initial implementation of the proposed standard (36 months analyses + 24 months Corrective Action Plan development). Then, depending upon the outcome, a more realistic implementation plan for the Corrective Action Plans can be developed. The Corrective Action Plan for the extreme events Requirement R4, Part 4.6 should be completely removed; along with the corresponding VRF/VSL languages; from the proposed standard as this is already addressed by the Commission approved TPL-001-4 Requirement R4, Part 4.5.	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Allow planning engineer(s) flexibility in their annual planning assessment pertaining to operational and system protection studies. Avoid “in consultation with the Realiability Coordinator” language.	
Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
The SPP Standards Review Group recommends that the drafting team develop language for section 2.4.3 that is consistent with section 2.1.3.	
Likes 0	
Dislikes 0	
Response	
Kayleigh Wilkerson - Lincoln Electric System - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Reliability Standard IRO-017-1 R3 requires each PC and TP to provide its Planning Assessment to impacted RCs. To better consolidate related requirements, recommend adding the RC as a recipient of the Planning Assessment in TPL-001.	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes

Document Name	
Comment	

Duke Energy recommends that when providing addiotional clarity/rationale on the subject of redundancy, the drafting team consider referring to a technical paper developed by the System Protection Control Task Force developed in 2008 titled: “Protection System Reliabilty: Redundancy of Protection System Elements”. Some aspects of this document may be helpful in providing additional clarity on this topic for the industry.

Likes 0	
Dislikes 0	
Response	

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	Yes
Document Name	
Comment	

(1) The Standards Authorization Request associated with this project provided the SDT an opportunity to evaluate requirement retirements under Paragraph 81 criteria. We believe Requirements R5, R6, R7, and R8 fall under such criteria. Documenting acceptable voltage limits and deviations and defining instability criteria for Cascading and uncontrolled islanding events are all necessary, yet are likely documented as assumptions and technical rationales listed within Planning Assessments. Moreover, these criteria are not directly associated with the required execution of conducting studies. The identification of study coordination roles and responsibilities through meeting minutes and distribution of Planning Assessment results to appropriate entities within a specific time period are administrative activities. Further proof is that these requirements do not have performance-based VSLs identified, particularly R8 which doesn’t even have a VSL identified at all.

(2) The proposed Evidence Retention period identified within the standard does not identify Measure M8.

(3) We thank you for this opportunity to provide these comments.

Likes 0	
Dislikes 0	
Response	

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
In Part 1.2 of section C on page 16, the new language identifying the Measures for which the responsible entity must retain evidence of compliance appears to incorrectly exclude Measure M8. This appears to be a typo.	
Likes 0	
Dislikes 0	
Response	
Jeffrey Watkins - Berkshire Hathaway - NV Energy - 6 - WECC	
Answer	Yes
Document Name	
Comment	
Similar to the comments provided in Question 2 for Requirement 2, Part 2.4.5, NVE has concerns about possible resource issues for performing a dynamic analysis for all P1 events. NVE feels that the transmission planners should continue to use their engineering judgment and discretion to select which contingencies make the most sense to study for their system for the dynamic analysis.	
Likes 0	
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	

Answer	Yes
Document Name	
Comment	

The comment form did not ask of entities agreed with the proposed changes to requirement R2.1.3, so Peak is providing those comments here. Peak does not agree with the proposed revisions in requirement R2.1.3. The proposed revision states, *"[Qualifying studies need to include the following conditions:] R2.1.3. P1 events in Table 1, **as selected in consultation with the as directed Reliability Coordinator**, with known outages modeled as specified in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled."* Peak disagrees with this proposed revision for many of the same reasons we disagree with the proposed changes to requirement R1.1.2. Overall, both proposals involve the RC in matters that are outside the RC's timeframe of assessment responsibility.

Additionally, the proposed requirement R2.1.3 is confusing to Peak. Is this standard requiring the RC to be consulted to determine ***which*** single P1 Contingencies the PC/TP needs to include in their studies? It is unclear to Peak exactly what the proposed changes to this requirement is trying to accomplish.

Peak as an RC requires operations reliability for ***all*** P1 Contingency events…not just ***certain*** ones. Involving the RC in the selection of P1 Contingencies that a given PC/TP should include in their studies is burdensome for RCs and does not provide any tangible reliability benefit. This proposed requirement creates an implied expectation for the RC to have already performed some kind of screening of P1 events and for the RC to relay any critical P1 performance related issues to the PC/TPs as part of the proposed consultation. Peak believes that this kind of analysis is above and beyond the expectations for RCs today, and that the standard should in no way create such an implied responsibility for RCs. Peak believes that identifying the P1 Contingencies that should be included in a PC/TP's Planning Assessment is purely a PC/TP responsibility and should not involve RCs explicitly in the standard.

By default, proposed requirement R2.1.3 requires the RC to do something in order for the TP/PC to be compliant – which in effect is a requirement for the RC. Peak believes this is not a good approach for writing standards. If the RC does not participate in this consultation, or if the consultation is "weak", is the PC/TP faced with a potential compliance ramifications? If such is the case, is the RC subject to any compliance ramifications?

Additionally, given the high number of PCs and TPs in the Western Interconnection, it is impractical for the Peak as an RC to have a prominent role in the determination of the P1 Contingencies a given PC/TP should include in their studies.

Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no ISO-NE, NYISO and NextEra	
Answer	Yes
Document Name	
Comment	
Requirement 2 – 2.7.1: the reference to Special Protection Systems (SPS) should be replaced by Remedial Action Schemes (RAS). Requirement 4 – 4.1.1: the reference to Special Protection Systems (SPS) should be replaced by Remedial Action Schemes (RAS). Order 786 specifically mentions that TPL-001 is intended to analyze the Near-Term Transmission Planning Horizon and requires annual assessments using Year One or year two, and year five. We agree that 1-, 2-, and 5-year forward looking is the appropriate and intended timeframe to be evaluated by the requirements of TPL-001. Therefore, only outages planned for this timeframe (more than 12-months forward) are appropriate to be required to be analyzed as a requirement of a Transmission Planning standard such as TPL-001. Outages planned to occur within the next 12-months should be analyzed per the Operations Planning requirements of IRO-017 which is intended to cover the Operations Planning time horizon. Using a bright-line of 12-months to determine the applicability of IRO-017 vs TPL-001 gives clarity and certainty of the appropriate requirements to be met.	
Likes 0	
Dislikes 0	
Response	

Payam Farahbakhsh - Hydro One Networks, Inc. - 1,3	
Answer	Yes
Document Name	
Comment	

We recommend including in the standard, as an attachment, guidelines and examples that provide clarity for footnote 13. This will allow the industry to have a consistent approach when the P5 planning events and Extreme events are evaluated.	
Likes 0	
Dislikes 0	
Response	
Darnez Gresham - Berkshire Hathaway - PacifiCorp - 6 - WECC	
Answer	Yes
Document Name	
Comment	
Please refer to comments for Question 1.	
Likes 0	
Dislikes 0	
Response	
Shawn Abrams - Santee Cooper - 1,3,5,6, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Comments: We agree that the data request and analysis after Order No. 754 was a good first step towards addressing the single points of failure in the protection system and the proposed language in TPL-001-5 is an improvement upon that criteria. The added/clarified language in the draft TPL-001-5 for P5	

and stability performance extreme events 2e-2h along with footnote 13 will, however, require the PCs and TPs to perform a lot more analyses than was originally performed for Order No. 754 data request. The criteria for buses to be tested under Order No. 754 data request required 4 or more circuits at 200 kV or higher, and, 6 or more circuits between 100 kV to 200 kV. The proposed TPL-001-5 language requires ALL BES buses; regardless of how many circuits terminate at each BES bus; to be tested. This will increase the findings for P5 Planning events for which the performance requirement is more restrictive than the performance measure in Table C of the data request.	
Likes 0	
Dislikes 0	
Response	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	
Comment	
When analyzing single-point-of-failure contingencies for protection schemes under three-phase faults as extreme events, it is important to note that a particular scheme could be fully redundant for three-phase faults whereas it is not redundant for single-phase-to-ground faults. For example, when three-phase faults are considered, there will be three current transformers involved and perhaps three relay units involved (particularly for lines protected by electromechanical relay units, which are often single-phase units), and if these components are the only sources of non-redundancy for a P5 contingency evaluated for a single-phase-to-ground fault, the scheme may not be applicable to single-point-of-failure for evaluating three-phase faults as an extreme event. The wording of the standard should ensure that this distinction can be made.	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1	
Answer	Yes

Document Name	
Comment	
ATC notes that the reliability impacts from actual extreme stability 2e-2h events are expected to be much less severe than the reliability impacts found in the FERC Order 754 analyses because the Order 754 analyses did not take into account the operation of bus tie breakers, which significantly reduce the extent of contingencies that involve bus sections.	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
1. Define SPF “single point of failure” at the first time occurance in “Rationale for Requirement R4 Part 4,6” , page 11 of 38 in the Redline version. 2. It looks like the last sentence of Requirement R4.5 “If the analysis concludes there is Cascading caused by ………” looks redundant after introducing requirement R4.6.	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	

Comment	
WAPA believes there is risk with the proposed changes of the single point of failure (SPF) language that will not significantly improve reliability. There is likelihood this change may even reduce reliability by having the CAPs force entities to redirect its limited resources away from other important reliability needs to solve SPF identified issue. Further, implementation of the CAPs may likely cause significant mis-ops while system protection systems are being modified to eliminate SPFs thus reducing reliability and increase risk to the transmission system. Frequency of these SPF events are so seldom, they do not warrant the cost to eliminate unless there are significant risks to the transmission system such as instability and cascading. No data has been provided to demonstrate that SPFs have been a significant factor in system outages.	
Likes 0	
Dislikes 0	
Response	
Dori Quam - NorthWestern Energy - 1,3 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Refer to comments for Question 1.	
Likes 0	
Dislikes 0	
Response	
larry brusseau - Corn Belt Power Cooperative - 1	
Answer	Yes
Document Name	

Comment	
Corn Belt agrees with the NSRF concerns that the number of additional dynamic analyses for P1 and P2 needs to be bounded in some reasonable fashion for Requirement 2, Part 2.4.5. Since NERC Protection Systems are referenced, the NSRF recommended that the same PRC-005-6 exclusions for individual wind and solar generators be added to the applicability section: From PRC-005-6: 4.2.6 Protection Systems and Sudden Pressure Relaying for the following BES generator Facilities for dispersed power producing resources identified through Inclusion I4 of the BES definition: 4.2.6.1 Protection Systems and Sudden Pressure Relaying for Facilities used in aggregating dispersed BES generation from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100kV or above. Also noted that the reliability impacts from actual extreme stability 2e-2h events are expected to be much less severe than the reliability impacts found in the FERC Order 754 analyses because the Order 754 analyses did not take into account the operation of bus tie breakers, which significantly reduce the extent of contingencies that involve bus sections.	
Likes 0	
Dislikes 0	
Response	
John Babik - JEA - 1,3,5	
Answer	Yes
Document Name	Table A.png
Comment	
We agree that the data request and analysis after Order No. 754 was a good first step towards addressing the single points of failure in the protection system and the proposed language in TPL-001-5 is an improvement upon that criteria. The added/clarified language in the draft TPL-001-5 for P5 and stability performance extreme events 2e-2h along with footnote 13 will, however, require the PCs and TPs to perform a lot more analyses than was originally performed for Order No. 754 data request.	

The criteria for buses to be tested (Table A; See Enclosed) under Order No. 754 data request required 4 or more circuits at 200 kV or higher, and, 6 or more circuits between 100 kV to 200 kV. However, the assessment according to the proposed TPL-001-5 requires ALL BES buses; regardless of how many circuits terminate at each BES bus; to be tested. Due to this more in-depth analyses now required, there will definitely be a significant new findings for P5 Planning events for which the performance requirement is more restrictive than the performance measure (Table C; See Enclosed) under data request. Before the industry assesses the entire BES (implementation plan: 36 months) followed by the development of the Corrective Action Plans just for P5 events with the proposed Footnote 13 (implementation plan: additional 24 months); it will be very pre-mature at this time to grant 60 months for the Corrective Action Plan implementation. It will be logical to have another survey/data request performed after 60 months from the initial implementation of the proposed standard (36 months analyses + 24 months Corrective Action Plan development). Then, depending upon the outcome, a more realistic implementation plan for the Corrective Action Plans can be developed. The Corrective Action Plan for the extreme events Requirement R4, Part 4.6 should be completely removed; along with the corresponding VRF/VSL languages; from the proposed standard as this is already addressed by the Commission approved TPL-001-4 Requirement R4, Part 4.5.	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
The corresponding changes to IRO-017 relative to R 1.1.2 as recommended in the PC report to the drafting team should also be pursued.	
Likes 0	
Dislikes 0	
Response	

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA believes the drafting team should consider the economical impact of requiring Corrective Action Plans for low probability extreme events, especially if the type of events have not occurred in the past or are not known to cause severe consequences. BPA has suggested edits to the requirement language for the following: **R1.1.2.** Known outage(s) of generation or Transmission Facility(ies) as selected in consultation with its Transmission Operator for outage durations that occur in the Near-Term Planning Horizon for analyses pursuant to Requirement R2, parts 2.1.3 and R. 2.4.3 **R2.1.3.** P1 events in Table 1, as selected in consultation with its Transmission Operator, with the known outages modeled as specified in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled. **R4.6.** If the analysis concludes there is Cascading caused by the occurrence of Table 1 extreme events listed in the stability column for events 2e-2h, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted. **R4.6.1** and **R4.6.2** deleted.	
Likes 0	
Dislikes 0	
Response	

Bridget Silvia - Sempra - San Diego Gas and Electric - 1,3,5	
Answer	Yes
Document Name	
Comment	

The SDT should consider changing the purpose statement of TPL-001 (section A.3). It identifies the wrong goal. The "Purpose" of the requirement is not to establish a requirement. The purpose of the requirement is to ensure that the Bulk Electric System will have the resources necessary to meet system load while also meeting performance requirements. This is done by requiring the TP/PC to assess the future (forecasted) system needs of its portion of the Bulk Electric System using software tools.

The SDT should consider limitations on available data, the capabilities of analysis software (power flow, dynamics and short circuit) and the burden placed on the TP/PC. (More paperwork does not translate into better reliability).

Likes 0	
Dislikes 0	

Response

Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF

Answer	Yes
Document Name	

Comment

The NSRF has concerns that the number of additional dynamic analyses for P1 and P2 needs to be bounded in some reasonable fashion for Requirement 2, Part 2.4.5.

Since NERC Protection Systems are referenced, the NSRF recommends that the same PRC-005-6 exclusions for individual wind and solar generators be added to the applicability section:

From PRC-005-6:

4.2.6 Protection Systems and Sudden Pressure Relaying for the following BES generator Facilities for dispersed power producing resources identified through Inclusion I4 of the BES definition:

4.2.6.1 Protection Systems and Sudden Pressure Relaying for Facilities used in aggregating dispersed BES generation from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100kV or above.

The NSRF notes that the reliability impacts from actual extreme stability 2e-2h events are expected to be much less severe than the reliability impacts found in the FERC Order 754 analyses because the Order 754 analyses did not take into account the operation of bus tie breakers, which significantly reduce the extent of contingencies that involve bus sections.	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1,3,5	
Answer	Yes
Document Name	
Comment	
Order 786 specifically mentions that TPL-001 is intended to analyze the Near-Term Transmission Planning Horizon and requires annual assessments using Year One or year two, and year five. We agree that 1-, 2-, and 5-year forward looking is the appropriate and intended timeframe to be evaluated by the requirements of TPL-001. Therefore, only outages planned for this timeframe (more than 12-months forward) are appropriate to be required to be analyzed as a requirement of a Transmission Planning standard such as TPL-001. Outages planned to occur within the next 12-months should be analyzed per the Operations Planning requirements of IRO-017 which is intended to cover the Operations Planning time horizon. Using a bright-line of 12-months to determine the applicability of IRO-017 vs TPL-001 gives clarity and certainty of the appropriate requirements to be met.	
Likes 0	
Dislikes 0	
Response	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6	
Answer	Yes
Document Name	

Comment	
Requirement 2 – 2.7.1: the reference to Special Protection Systems (SPS) should be replaced by Remedial Action Schemes (RAS). Requirement 4 – 4.1.1: the reference to Special Protection Systems (SPS) should be replaced by Remedial Action Schemes (RAS).	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
We recommend including in the standard, as an attachment, some guidelines and examples that clarify the type of protection failures that need to be studied. This will allow the industry to have a consistent approach when the P5 planning events and extreme events are evaluated.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Although it is not specified as part of the scope if this project, Texas RE is concerned the standard does not require studying unknown outages in off-peak conditions in addition to the known outages. Studying all conditions, known and unknown, addresses the "planned maintenance outages of significant facilities" in FERC order 786, paragraph 40. Even routine maintenance outages that occur during off-peak load conditions could be significant, but TPs and PCs may not have the information needed to meet the "known" requirement when TPL studies are being performed.	
Likes 0	
Dislikes 0	
Response	

John Merrell – Tacoma Public Utilities (Tacoma, WA) - 3	
Answer	Yes
Document Name	
Comment	
1. Footnote 13.4 has numerical issues. As explained above, Tacoma Power would prefer explicit requirements for each of the 5 bullet points in the Protection System Definition. If 13.4 is kept, it should be revised to say "A single control circuitry path associated with protective functions between the DC panel and a trip coil of the circuit breakers or other interrupting devices." In the current draft, it is unclear whether there is a requirement to have dual trip coils. 2. The combination of a P1 event in Table 1 and known outages modeled as in Requirement R1, Part 1.1.2 is not a single contingency. Thus, the system performance requirement should be less stringent than for a P1 event. For these types of events, interruption of Firm Transmission Service and Non-Consequential Load Loss should be allowed.	
Likes 0	
Dislikes 0	
Response	

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Unofficial Comment Form

Project 2015-10 Single Points of Failure
TPL-001-5

Do not use this form for submitting comments. Use the electronic form to submit comments on **TPL-001-5 – Transmission System Planning Performance Requirements** . The electronic form must be submitted by **8 p.m. Eastern, Wednesday, May 24, 2017.**

Additional information is available on the project page. If you have questions, contact Standards Developer, Latrice Harkness (via email), or at (404) 446-9728.

Background Information

The SPCS and the SAMS conducted an assessment of protection system single points of failure in response to FERC Order No. 754, including analysis of data from the NERC Section 1600 Request for Data or Information. The assessment confirms the existence of a reliability risk associated with single points of failure in protection systems that warrants further action**.**

Additionally, the two directives from FERC Order No. 786 (p. 40 and p. 89) and updates to the MOD reference in Requirement R1, Measure M1 and the Violation Severity Levels sections have been added to the scope of the project.

Questions

1. Do you agree with the proposed changes to Requirement 1, Part 1.1.2 that move away from the 6 month duration outage to limited known outages selected by the Planning Coordinator (PC)/Transmission Planner (TP) in consultation with their Reliability Coordinators (RCs) for the time horizon of the operations planning horizon through the near term planning horizon?

   ☐ Yes
   ☒ No

   Comments:
   Corn Belt agrees with the SPP Standards Review Group and its clarification of an important issue regarding the expectations of regulatory staff on the impacts of Requirement 1, Part 1.1.2. The clarification is about the differences in power flow case topologies used by SPP Operations and SPP Planning. Issues found in the operating horizon would be specific to that point in time and would take into consideration any planned outages, forced outages, generation dispatch, transfers, and load levels that would cause concerns. These operating horizon variables would be changing from minute to hour to day to week to month to season to year. The same outage placed in a planning horizon assessment would be placed into a model that has a lot fewer outages, different generation dispatch, different transfer levels, and different load levels. The topology differences between the two power flow models is significant enough that the operation horizon outages would more than likely not cause issues in the Transmission System Planning Performance Requirements (TPL) Assessment. Further, the SPP Standards Review Group states that trying to mimic, follow, or forecast these operating horizon outages in a meaningful manner would be a moving target. This is due to the fact that most of the planned outages are due to maintenance and capital projects that usually do not re-occur within a 3-5 year period, if ever. The SPP Standards Review Group also found the proposed language to be vague and ambiguous, regarding the timeframe, and therefore would be hard to defend during an audit.

   Corn Belt agrees with the SPP Standards Review Group that the language is unclear as to whether outages should be evaluated only in the season for which they are planned or whether they should be evaluated for the peak or off-peak 1 or 2, and 5 planning horizon. In addition, the reference to the number of additional cases and the associated seasons that could be required. Corn Belt agrees with the SPP Standards Review Group suggested proposed language that would tie this process to the TOP Standards instead of the TPL Standards as this is pertaining more to operation related issues.

   Also concerned that this could significantly increase the number of near term cases created and studied and add significant work load to tune L&R for these cases. Concern this will significantly increase PC/TP study work load without benefit due to undetermentant amount of outages that need studied. Even though the 6 month duration may not be perfect, it did provide specific criteria to select outages to study. Concern this change will result in significant wasted time and effort to produce results that won't ultimately be used because the same outages will be restudied in ops horizon.

Firmly disagree with the bullet in the Rationale for Requirement R1 Part 1.1.2. "Relying on Category P3 and P6 is not sufficient and does not cover maintenance outages (see P 44);" Category P3 and P6 does sufficiently cover most maintenance outages any utility would expect and the criteria for R1.1.2 should define outages beyond those that are normaly studied as Category P3 and P6.

Futher, the word "limited" in the comment form Question 1 above is not in the proposed language of R1.1.2, and is misleading by implying the intent is for a "small number of" outages. If the intent is for the PC/TP's to study only a limited amount of outages (beyond those already studies as P3 and P6's) then edit the language to state so.

Outages of concern to be studied separately. Base case assumptions.[A1]

Suggested Language:[A2]
R1.1.2 Known critical outage(s) of generation or Transmission Facility(ies) as selected in consultation with the Reliability Coordinator for the Near-Term Planning Horizon for analyses pursuant to Requirement R2, parts 2.1.3 and 2.4.3.

2. Do you agree with the proposed changes to Requirement 2, Part 2.4.5 which addresses the Federal Energy Regulatory Commission (FERC) order to add the spare equipment with long lead time to the dynamics analysis?

☒ Yes
☐ No

Comments: : Corn Belt agrees, but suggests that "more than 1 year" be substituted for long lead time throughout TPL-001-5 where appropriate for better clarity.

Concerns that the number of additional dynamic analyses to include long lead time items taking more than 1 year for P1 and P2 needs to be bounded. There are real computational constraints that could take months to run. An example could give the Transmission Planner discretion to chose the worst conditions.

3. Do you agree with the further clarification of relay to components of a Protection System with the additional footnote to clarify P5 and extreme events?

☐ Yes
☒ No

Comments:

Recommend that "Cascading" be replaced with a specific MW number such as the loss of 2,000 MW of generation as referenced in the EOP-004 standard. The term "Cascading" remains too vague and subject to change. A MW threshold is a better "bright line" criteria.

Recommend each BES Protection System component class be covered explicitly in Footnote 13 along with an inclusion or exclusion justification. Abrief Protection System scope for Footnote 13 may also be helpful.

Ask if relays should be limited to electromechanical relays as the SPCS/SAMS Order 754 report identified risk depends upon the relay type and protection system design
(meaning multiple relays to respond to a fault). If an entity shows no electromechanical primary or aux relays can that be sufficient to exclude from being redundant?

Ask if communications systems should be eliminated except for RAS. The SPCS/SAMS Order 754 report identified communications systems posed a lower risk level.

Example NERC Defined Protection System Component Classes, Scope and Applicability:

NERC Bulk Electric System (BES) protective relays/sudden pressure relays/reclosing relays:
NERC BES PRC-005-6 Protection System electromechanical primary and auxillary relays are included in footnote 13. This includes PRC-005-6 identified sudden pressure and reclosing relays.

NERC BES associated communication systems:
NERC BES PRC-005-6 associated communication systems are included in footnote 13.
Redundant communications system for footnote 13 would be two communications channels. Redundant communications for Footnote 13 does not require separate and diversely routed communications towers.

NERC BES Voltage and current sensing devices:

NERC BES PRC-005-6 voltage and current sensing devices are not included in footnote 13. The SPCS/SAMS Order 754 report identified that voltage and current sensing devices were robust and posed a lower risk level.

NERC BES Station batteries:

NERC BES PRC-005-6 Station batteries are included in footnote 13 with the following exceptions. A single station DC supply is allowed if monitored for low voltage and open circuit alarms to a centrally monitored location within 24 hours of abnormal condition detection.

NERC BES Battery Chargers:
NERC BES PRC-005-6 station battery chargers are included in footnote 13. A single station charger is allowed if the battery bank is monitored for low voltage and open circuit alarms to a centrally monitored location within 24 hours of abnormal condition detection.

NERC BES DC control circuitry:
NERC BES PRC-005-6 DC control circuitry is included in footnote 13 but its outcome is already considered in the P4 stuck breaker category. Whether stuck breaker of a DC control circuit failure, the end result is the same.

4. Do you agree with the proposed Requirement 4, Part 4.6 additions which require a Corrective Action Plan for this subset of Table 1 extreme events (footnote 13, 2e-2h)?

☐ Yes
☒ No

Comments:
The additions which require a Corrective Action Plan for the subset of Table 1 extreme events (footnote 13, 2e-2h) are beyond what is stated in the conclusion of the SPCS and SAMS "Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request" report. This report recommended the following:

Modify TPL-001-4 (Part 4.5) so that extreme event assessments must include evaluation of the three-phase faults the described component failures of a Protection System[13] that produce the more severe system impacts. For example, add a new second sentence that reads "[t]he list shall consider each of the extreme events in Table 1 – Steady State & Stability Performance Extreme Events; Stability column item number 2."

Corrective Action Plans for low probability extreme events should not be required. However, it is reasonable that if Cascading is caused by the occurrence of an extreme event, an evaluation of possible actions designed to reduce the likelihood be conducted, as is currently stated in TPL-001-4 for extreme events (R4.5). Based on the conlusion of the above mentioned SPCS and SAMS report, it is understood that the intent should be to clarify that **both** three-phase faults with stuck breaker **and** failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing shall be considered as part of those extreme events in Table 1 that are expected to produce more severe System impacts in accordance with the existing language of TPL-001-4 R4.5. In other words, clarify that the "or" in Table 1 – Extreme Stability Events should not be interpreted as you only need to consider either stuck breaker or relay failure in R4.5. This is accomplished by simply breaking these events apart in Table 1 as shown below (and as in the current TPL-001-5 draft):

2. Local or wide area events affecting the Transmission System such as:
    a. 3Ø fault on generator with stuck breaker[10] resulting in Delayed Fault Clearing.
    b. 3Ø fault on Transmission circuit with stuck breaker[10] resulting in Delayed Fault Clearing.
    c. 3Ø fault on transformer with stuck breaker[10] resulting in Delayed Fault Clearing.
    d. 3Ø fault on bus section with stuck breaker[10] resulting in Delayed Fault Clearing.
    e. 3Ø fault on generator with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.
    f. 3Ø fault on Transmission circuit with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.
    g. 3Ø fault on transformer with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.
    h. 3Ø fault on bus section with failure of a non-redundant comoponent of a Protection System[13] resulting in Delayed Fault Clearing.
    i. 3Ø internal breaker fault.
    j. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

To further emphasize this point, refer to the alternatives for addressing reliability risks associated with single points of failure outlined in Charper 2 of the SPCS and SAMS report:

- *Place additional emphasis on assessment of a three-phase fault and protection system failure*
    - *Provideds assurance that areas where a three-phase fault accompanied by a single point of failure that will cause an adverse impact are identified and evaluated*
- *Elevate to a planning event with its own system performance criteria*

  - *Probability of three-phase fault with a protection system failure is low enough that it does not warrant a planning event*
- *Keep as an extreme event with no change (other than footnote 13)*
  - *Does not provide assurance a three-phase fault with protection system failure is studied in planning assessments*

From the above language describing the considered alternatives, it can be ascertained that the concern is ensuring that the language in the standard be updated to assure three-phase faults with protection system failure are studied in planning assessments, not that a “subset of Table 1 Extreme Events” be created that are treated differently than other Extreme Events by elevating them to requiring Corrective Action Plans because “the probability of three-phase faults with a protection system failure is low enough that it does not warrant a planning event”. Furthermore, there is no technical justification to elevate a three-phase fault with failure of a non-redundant component of a Protection System events above three-phase fault with stuck breaker events.

Although Corn Belt strongly disagrees with requiring a Corrective Action Plan for this “subset of Table 1 extreme events”, if this requirement is carried forward Corn Belt recommends creating a separate P8 Event for these three-phase failure of a non-redundant component of a Protection System events because it makes Table 1 clearer to read, understand and differentiate between what is required of these events compared to other Extreme Events.

Table 1 – Steady State & Stability Performance Planning Events
Steady State & Stability (all events): a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur. b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0. c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event. d. Simulate Normal Clearing unless otherwise specified. e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings. **Steady State Only (P0 through P7 events only)**: f. Applicable Facility Ratings shall not be exceeded. g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner. h. Planning event P0 is applicable to steady state only. i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements. **Stability Only (P1 through P7 events only):** j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P8 Multiple Contingency *(Fault plus non-redundant component of a Protection System failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	3Ø	EHV, HV	Yes	Yes

5. Do you agree with the drafting team's approach which doesn't add additional applicable entities to the applicability of the standard? (e.g. RC, Transmission Operator (TO), Generator Operator (GO), Distribution Provider (DP))

   ☐ Yes
   ☒ No

   Comments: Corn Belt agrees with the SPP Standards Review Group proposal that a standard applicable to the Reliability Coordinator (RC) address RC requirements should be considered. Potentially, it could be added to NERC Stanadard IRO-017.

   Corn Belt agrees with the SPP Standards Review Group suggestion that the Transmission Owners (TOs) and Generator Owners (GOs) should be added to the applicability section of the standard and have requirements to respond to TP/PC requests for information to help the PC/TP developIoretive Action Plans (CAPs).

6. Do you agree with the 36 month implementation period to address All Requirements except for Requirement R4, Part 4.6, and Requirement 2, Part 2.7 associated with P5 due to Footnote 13 bullets 2, 3 and 4, as well as the definitions?

   ☒ Yes
   ☐ No

   Comments: As long as the implementation plan refers to the development of required CAPs, not the placing the required CAPs in service.

7. Do you agree with the 60 month implementation plan for Requirement 4, Part 4.6 and Requirement 2, Part 2.7 associated with P5 due to Footnote 13 bullets 2, 3 and 4?

   ☐ Yes
   ☒ No

   Comments:

We (utilities) probably already know that we cannot meet the 60 month implementation period. Capital improvements can not be determined and implemented in a 60 month time period. Forced compliance to 60 months would require undesirable mitigations such as system protection adjustments that might reduce system security, misoperations due to changes in protection systems that result in non-standard configurations and changes to maintenance practices due to non-standard application of protection systems.

There is a concern that utilities will not be able to meet the 60 month implementation plan in a reliabile manner. Unlike other potential areas identified in Planning Studies where the system may not meet the System Performance Requirements outlined in Table 1, other temporary reliable solutions, such as the use of Operating Procedures, are available that can be implemented until a long term solution (capital project) is completed. In many instances the only way to fully mitigate impacts resulting from "failure of a non-redundant component of a Protection System" event is to add redundancy. If this cannot be achieved in 60 months utilities may be forced to make undesirable system protection adjustments that could result in a higher rate of misoperations, reduction of system security, and reduced reliability until redundancy can be added. This should not be interpreted as utlities ignoring the importance of adding redundancy at critical points on the system, but implementation should be done on a cost/benefit (risk assessment) basis that takes into consideration the resources individual utilities have to adequately address areas of concerns resulting from~~orm~~ single points of failure. In other words, the timing requirement of the implementation plan should not be so prescriptive that it leads to greater reliability risks than the conerns associated with the potential consequences of a single point of failure event.

8. Are you aware of any other governing documents that could be in conflict with the current proposal for this draft of the standard?

☐ Yes
☒ No

Comments:

9. Do you agree with the teams proposed changes to align the VRF/VSLs for Requirement 4, Part 4.6 with the VRF/VSLs for Requirement 2, Part 2.7?

☒ Yes
☐ No

Comments:

10. Do you have any other general recommendations/considerations for the drafting team?

☒ Yes
☐ No

Comments:
Corn Belt agrees with the NSRF concerns that the number of additional dynamic analyses for P1 and P2 needs to be bounded in some reasonable fashion for Requirement 2, Part 2.4.5.

Since NERC Protection Systems are referenced, the NSRF recommended that the same PRC-005-6 exclusions for individual wind and solar generators be added to the applicability section:

From PRC-005-6:

4.2.6 Protection Systems and Sudden Pressure Relaying for the following BES generator Facilities for dispersed power producing resources identified through Inclusion I4 of the BES definition:

4.2.6.1 Protection Systems and Sudden Pressure Relaying for Facilities used in aggregating dispersed BES generation from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100kV or above.

Also noted that the reliability impacts from actual extreme stability 2e-2h events are expected to be much less severe than the reliability impacts found in the FERC Order 754 analyses because the Order 754 analyses did not take into account the operation of bus tie breakers, which significantly reduce the extent of contingencies that involve bus sections.

Unofficial Comment Form

Project 2015-10 Single Points of Failure
TPL-001-5

Do not use this form for submitting comments. Use the electronic form to submit comments on **TPL-001-5 – Transmission System Planning Performance Requirements** . The electronic form must be submitted by **8 p.m. Eastern, Wednesday, May 24, 2017.**

Additional information is available on the project page. If you have questions, contact Standards Developer, Latrice Harkness (via email), or at (404) 446-9728.

Background Information

The SPCS and the SAMS conducted an assessment of protection system single points of failure in response to FERC Order No. 754, including analysis of data from the NERC Section 1600 Request for Data or Information. The assessment confirms the existence of a reliability risk associated with single points of failure in protection systems that warrants further action**.**

Additionally, the two directives from FERC Order No. 786 (p. 40 and p. 89) and updates to the MOD reference in Requirement R1, Measure M1 and the Violation Severity Levels sections have been added to the scope of the project.

Questions

1. Do you agree with the proposed changes to Requirement 1, Part 1.1.2 that move away from the 6 month duration outage to limited known outages selected by the Planning Coordinator (PC)/Transmission Planner (TP) in consultation with their Reliability Coordinators (RCs) for the time horizon of the operations planning horizon through the near term planning horizon?

   ☐ Yes
   ☒ No

   Comments: 1. IRO-017-1 already requires the RC to maintain a coordination process for the Near-Term Transmission Planning Horizon. The proposed approach in TPL provides little guidance to the RC/TP/PC as to what level of detail to model future outages. This may lead to widely varying practices across regions.

   2. We support the other approaches suggested by FERC to limit the scope based on both time and outage significance. The proposed alternate for R1.1.2 is:
   Schedule outage(s) of Generation or Transmission Facility(ies) that are identified by the Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and lasting longer than 90 days.

   3. It is important to note the difference between a planned outage in the sense: (1) that maintenance crews "plan" for insulation testing of every transformer every three years, and (2) that a nuclear plant plans to be offline for refueling from exactly 3/3/2019 @ 19:30 to 9/15/2019 08:00. In the former case, the exact outage dates are both unknown and highly flexible, whereas with the latter the outage has specific dates that can be modeled and it must occur regardless of system conditions. The previous 6 month limit served as a screen to identify only those outages which were likely to occur during critical system conditions. Most maintenance is scheduled to avoid system peaks.

   4. It unclear how to model planned outages in year one, year three or year four if the TPL planning assessment uses year two and year five.

2. Do you agree with the proposed changes to Requirement 2, Part 2.4.5 which addresses the Federal Energy Regulatory Commission (FERC) order to add the spare equipment with long lead time to the dynamics analysis?

   ☐ Yes
   ☒ No

3. Do you agree with the further clarification of relay to components of a Protection System with the additional footnote to clarify P5 and extreme events?

☐ Yes
☒ No

Comments:
1. Tacoma Power does not agree that all parts of the Protection System should be treated identically with regards to single point failures. As identified the order 754 final report, some protection system components such as protective relays, auxiliary relays, and DC circuits downstream of the DC panel branch circuit protection have been documented as common causes of actual single point failures. The final report also identifies that AC inputs and the station DC supply pose much lower risk of failure to trip. The attached table shows an alternative set of contingencies that would implement a more risk-based approach to single point failures of each kind of component in the protection system.

2. Tacoma Power proposes P5 include the more common kinds of failures of the protection system that include 1) Protective relays which respond to electrical quantities; 2) A single communications system, necessary for correct operation of protective functions, which is not monitored; and 3) Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

3. New P8 and P9 contingencies for EHV facilities would address the remaining less likely to fail components of the protection system including (1) Voltage and current sensing devices providing inputs to protective relays, (2) Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply). Since these kinds of components are less likely to fail, allowing interruption of firm transmission service and nonconsequential load should be allowed for all voltage levels.

The 754 report found that only 0.7% of 100-199 kV buses had adverse system response from a single point of failure whereas 20% of EHV buses had adverse system response from a single point of failure. This disparity indicates efforts mitigating single component failures should be focused on the EHV system. The new P8 and P9 (i.e. the proposed d-h extreme events) should apply to just EHV elements.

Creating new events P8 and P9 would clarify that Corrective Action Plans are required for these contingencies whereas extreme events do not require CAPs.

4. Tacoma Power supports reformatting of Table 1, as it is currently quite confusing.

5. There appears to be confusion as to whether to monitor protection circuits, the battery bank or the main DC breaker for open circuit. Trip coil monitoring does not provide any assurance the batteries are connected. Furthermore, there appears to be a lack of publicly available evidence

that battery open circuit monitoring substantially lowers the risk of the protection system failing to trip. Dual batteries may be more appropriate for many EHV applications.

6. Battery monitoring system cost roughly the same amount as the set of batteries they monitor. Imposing additional costs for battery monitoring systems may lead to utilities replacing battery banks less often.

7. If the SDT continues to include monitoring as a viable option, these additional clarifications are need: (1) battery open circuit monitoring is required, (2) every breaker/fuse in the DC system must be monitored if it is a single point of failure, (3) a single trip coil is a single point of failure and is not mitigated by having trip coil monitoring unless there is independent breaker failure control circuitry, (4) low voltage monitoring threshold for battery voltage shall be coordinated with the battery design to give indication with at least 50% of battery capacity remaining, (5) auxiliary type relays for loss of DC may not be sufficient for low voltage monitoring of the battery, although they may be used for monitoring for loss of DC, and (6) non-battery-based DC systems require redundancy and should be addressed in a separate bullet under Footnote 13.

8. If monitoring of Protection System components is counted for purposes of TPL-001-5, is it the drafting team's intent that an entity would be obligated to maintain the alarming paths and monitoring systems under PRC-005-6 (Requirement R1, Part 1.2, and Table 2)? An entity should be allowed to consider monitoring for purposes of TPL-001-5 but treat the associated Protection System component(s) as unmonitored for purposes of PRC-005-6.

9. Additional clarification is requested on the demarcation between station DC supply and control circuitry for purposes of TPL-001-5. It is recommended that the main breaker of DC panels be considered part of the station DC supply.

4. Do you agree with the proposed Requirement 4, Part 4.6 additions which require a Corrective Action Plan for this subset of Table 1 extreme events (footnote 13, 2e-2h)?

☐ Yes
☒ No

Comments: Tacoma Power disagrees with the concept of requiring CAPs for extreme events. If events are critical enough to need a CAP, they should be listed as required contingencies. Please see our comments to question 2 with regard to which events at which voltage levels should have CAPs.

5. Do you agree with the drafting team's approach which doesn't add additional applicable entities to the applicability of the standard? (e.g. RC, Transmission Operator (TO), Generator Operator (GO), Distribution Provider (DP))

☒ Yes
☐ No

Comments: Tacoma Power agrees with the drafting team, provided that the Reliability Coordinator's role under Requirement R1, Part 1.1.2, is only advisory.

6. Do you agree with the 36 month implementation period to address All Requirements except for Requirement R4, Part 4.6, and Requirement 2, Part 2.7 associated with P5 due to Footnote 13 bullets 2, 3 and 4, as well as the definitions?

☐ Yes
☐ No

Comments:

7. Do you agree with the 60 month implementation plan for Requirement 4, Part 4.6 and Requirement 2, Part 2.7 associated with P5 due to Footnote 13 bullets 2, 3 and 4?

☐ Yes
☒ No

Comments: Are corrective action plans required to be developed within 60 months or to be completed within 60 months? Assuming the TP/PC takes most of the 36 months to implement the rest of TPL-001-5, the additional 24 months provides very little time for a TO/GO to actually implement construction projects.

8. Are you aware of any other governing documents that could be in conflict with the current proposal for this draft of the standard?

☐ Yes
☒ No

Comments:

9. Do you agree with the teams proposed changes to align the VRF/VSLs for Requirement 4, Part 4.6 with the VRF/VSLs for Requirement 2, Part 2.7?

☐ Yes
☐ No

Comments:

10. Do you have any other general recommendations/considerations for the drafting team?

☒ Yes
☐ No

Comments: 1. Footnote 13.4 has numerical issues. As explained above, Tacoma Power would prefer explicit requirements for each of the 5 bullet points in the Protection System Definition. If 13.4 is kept, it should be revised to say "A single control circuitry path associated with protective functions between the DC panel and a trip coil of the circuit breakers or other interrupting devices." In the current draft, it is unclear whether there is a requirement to have dual trip coils.

2. The combination of a P1 event in Table 1 and known outages modeled as in Requirement R1, Part 1.1.2 is not a single contingency. Thus, the system performance requirement should be less stringent than for a P1 event. For these types of events, interruption of Firm Transmission Service and Non-Consequential Load Loss should be allowed.

Unofficial Comment Form

Project 2015-10 Single Points of Failure

TPL-001-5

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Background Information

The SPCS and the SAMS conducted an assessment of protection system single points of failure in response to FERC Order No. 754, including analysis of data from the NERC Section 1600 Request for Data or Information. The assessment confirms the existence of a reliability risk associated with single points of failure in protection systems that warrants further action.

Additionally, the two directives from FERC Order No. 786 (p. 40 and p. 89) and updates to the MOD reference in Requirement R1, Measure M1 and the Violation Severity Levels sections have been added to the scope of the project.

Questions

1. Do you agree with the proposed changes to Requirement 1, Part 1.1.2 that move away from the 6 month duration outage to limited known outages selected by the Planning Coordinator (PC)/Transmission Planner (TP) in consultation with their Reliability Coordinators (RCs) for the time horizon of the operations planning horizon through the near term planning horizon?

☐ Yes
☒ No

Comments:

WAPA agrees with the intent to include significant impactful outages that are important to evaluate ahead of what is covered in the Operations Horizon, but we need to ensure that the language change to Requirement 1, Part 1.1.2 supports this intent. It is essential that the scope of outages be limited to significant planned outages that are not hypothetical in nature. Otherwise, there is a concern that this could significantly increase PC/TP study work without an appreciable benefit due to an undeterminant amount of outages that need to be studied. Outage scheduling changes could occur potentially leading to the results from the R1.1.2 analysis becoming irrelevant as it gets closer to when the outage will actually occur (Operations Horizon). These outages will need to be restudied in the Operations Horizon using more accurate information anyway. Even though the 6 month duration may not be perfect, it did provide specific criteria to select outages to study. There is a risk that the proposed language change to R1.1.2 could lead to it being left wide-open regarding what should be included in a Planning model because there are no parameters on what constitutes a significant planned outage.

WAPA disagrees with the bullet in the Rationale for Requirement R1 Part 1.1.2. "Relying on Category P3 and P6 is not sufficient and does not cover maintenance outages (see P 44);" Category P3 and P6 does sufficiently cover most maintenance outages any utility would expect and the criteria for R1.1.2 should define outages beyond those that are normaly studied as Category P3 and P6.

Futher, the word "limited" in the comment form Question 1 above is not in the proposed language of R1.1.2, and is misleading by implying the intent is for a "small number of" outages. If the intent is for the PC/TP's to study only a limited amount of outages (beyond those already studies as P3 and P6's) then edit the language to state so.

Suggested Language (add a qualifier to specify these outages should be critical/significant in nature and leave the ultimate decision upon what constitutes a significan planned outage to the PC/TP per R1 that, “shall maintain System models… to complete its Planning Assessment”):

R1.1.2 Known **critical** outage(s) of generation or Transmission Facility(ies) as selected in consultation with the Reliability Coordinator for the Near-Term Planning Horizon for analyses pursuant to Requirement R2, parts 2.1.3 and 2.4.3.

2. Do you agree with the proposed changes to Requirement 2, Part 2.4.5 which addresses the Federal Energy Regulatory Commission (FERC) order to add the spare equipment with long lead time to the dynamics analysis?

   ☒ Yes
   ☐ No

   Comments:

3. Do you agree with the further clarification of relay to components of a Protection System with the additional footnote to clarify P5 and extreme events?

   ☐ Yes
   ☒ No

   Comments:

   WAPA agrees with the intent but offers improvements to the language.

   In Order No. 786 (P69), FERC declined to direct that NERC revise this standard to apply to all protection system components, at least until NERC completed its analysis of the Order No. 754 data responses. After review of that data, the NERC SPCS and SAMS recommended including protective relays, DC control circuitry, and station DC supply in the standard. This recommendation was based on the survey results regarding the prevalence of non-redundant protective equipment and the simulated disturbance magnitude of a failure of non-redundant equipment. The SPCS and SAMS report, did not, however, quantify the likelihood of each type of non-redundant protection component failure. Thus, it is hard to fully agree with the SPCS/SAMS recommendations at this time (and the Standard Authorization Request is only to "consider" them rather than "address" them).

WAPA does not believe that it is necessary to include analysis of all of these non-redundant Protection System component failures in the TPL standards at this time. Alternatively, if they are included, then they should be treated similarly to the current treatment of Extreme Events where there are no strict performance requirements or mandates to create Corrective Action Plans. In fact, the SPCS and SAMS report suggested that auxiliary relay and lockout relay failures were the main culprit in previous disturbances but failures of other equipment are generally rare or unimpactful (p.7). If anything, the P5 category expansion should be limited to auxiliary and lockout relays. This would allow utilities to focus their money and attention to mitigating the most severe potential impacts rather than building redundancy into systems where it will most likely never be needed.

WAPA recently studied the cost of eliminating single points of failure at a typical older substion. WAPA estimates that building full redundancy will likely cost over $1.3 million and take about a year and a half to implement. The main reason why it takes this long is due to scheduling outages. During outage timeframes, WAPA may have to curtail transmission or generation schedules, which many WAPA customers and staff would view as a decrement to reliable operations. The commissioning of new relays also requires significant testing, which conceivably puts WAPA at greater risk for human error. Furthermore, WAPA does not have any record of a P5 or EE2d type of event in the last 50+ years. Just building redundancy into substations will be a challenge to explain to WAPA ratepayers, and it may prove extremely difficult if WAPA is required to add costs and time for DC control circuitry equipment. Instead, WAPA may desire to focus its limited resources on developing replacement plans for aging equipment (e.g. transformers) or improving security measures.

As a reference, here is the language from SAMS Table 1.3. *DC Control Circuitry: The protection system includes two independent DC control circuits with no common DC control circuitry, auxiliary relays, or circuit breaker trip coils. For the purpose of this data request the DC control circuitry does not include the station DC supply or the main DC* *distributionpanel(s), but does include all the DC circuits used by the protection system to trip a breaker, including any DC control circuit (branch) fuses or breakers at the main DC distribution panel(s).*

In addition to the concerns mentioned above, WAPA suggestions the following clarification of components of a protection system (Footnote 13).

Suggested Language:
For purposes of this standard, non-redundant components of a Protection System to consider are as follows:

1. A single protective relay which responds to electrical quantities used for primary protection;
2. A single communications system, necessary for correct operation of protective functions, which is not monitored or not reported;
3. A single DC supply associated with protective functions that is not monitored for both low voltage and open circuit, with alarms centrally monitored;
4. A single DC Control Circuitry that causes the primary and local backup protection system to not operate properly and triggers remote delayed clearing.

4. Do you agree with the proposed Requirement 4, Part 4.6 additions which require a Corrective Action Plan for this subset of Table 1 extreme events (footnote 13, 2e-2h)?

☐ Yes
☒ No

Comments:

The additions which require a Corrective Action Plan for the subset of Table 1 extreme events (footnote 13, 2e-2h) are beyond what is stated in the conclusion of the SPCS and SAMS "Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request" report. This report recommended the following:

Modify TPL-001-4 (Part 4.5) so that extreme event assessments must include evaluation of the three-phase faults the described component failures of a Protection System[13] that produce the more severe system impacts. For example, add a new second sentence that reads "[t]he list shall consider each of the extreme events in Table 1 – Steady State & Stability Performance Extreme Events; Stability column item number 2."

Corrective Action Plans for low probability extreme events should not be required. However, it is reasonable that if Cascading is caused by the occurrence of an extreme event, an evaluation of possible actions designed to reduce the likelihood be conducted, as is currently stated in TPL-001-4 for extreme events (R4.5). Based on the conlusion of the above mentioned SPCS and SAMS report, it is understood that the intent should be to clarify that **both** three-phase faults with stuck breaker **and** failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing shall be considered as part of those extreme events in Table 1 that are expected to produce more severe System impacts in accordance with the existing language of TPL-001-4 R4.5. In other words, clarify that the "or" in Table 1 – Extreme Stability Events should not be interpreted as you only need to consider either stuck breaker or relay failure in R4.5. This is accomplished by simply breaking these events apart in Table 1 as shown below (and as in the current TPL-001-5 draft):

2. Local or wide area events affecting the Transmission System such as:
    a. 3Ø fault on generator with stuck breaker[10] resulting in Delayed Fault Clearing.
    b. 3Ø fault on Transmission circuit with stuck breaker[10] resulting in Delayed Fault Clearing.
    c. 3Ø fault on transformer with stuck breaker[10] resulting in Delayed Fault Clearing.
    d. 3Ø fault on bus section with stuck breaker[10] resulting in Delayed Fault Clearing.
    e. 3Ø fault on generator with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.
    f. 3Ø fault on Transmission circuit with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.
    g. 3Ø fault on transformer with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.
    h. 3Ø fault on bus section with failure of a non-redundant comoponent of a Protection System[13] resulting in Delayed Fault Clearing.
    i. 3Ø internal breaker fault.
    j. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

To further emphasize this point, refer to the alternatives for addressing reliability risks associated with single points of failure outlined in Charper 2 of the SPCS and SAMS report:

- *Place additional emphasis on assessment of a three-phase fault and protection system failure*
    - *Provideds assurance that areas where a three-phase fault accompanied by a single point of failure that will cause an adverse impact are identified and evaluated*
- *Elevate to a planning event with its own system performance criteria*

- *Probability of three-phase fault with a protection system failure is low enough that it does not warrant a planning event*
- *Keep as an extreme event with no change (other than footnote 13)*
  - *Does not provide assurance a three-phase fault with protection system failure is studied in planning assessments*

From the above language describing the considered alternatives, it can be ascertained that the concern is ensuring that the language in the standard be updated to assure three-phase faults with protection system failure are studied in planning assessments, not that a “subset of Table 1 Extreme Events” be created that are treated differently than other Extreme Events by elevating them to requiring Corrective Action Plans because “the probability of three-phase faults with a protection system failure is low enough that it does not warrant a planning event”. Furthermore, there is no technical justification to elevate a three-phase fault with failure of a non-redundant component of a Protection System events above three-phase fault with stuck breaker events.

Although WAPA strongly disagrees with requiring a Corrective Action Plan for this “subset of Table 1 extreme events”, if this requirement is carried forward WAPA recommends creating a separate P8 Event for these three-phase failure of a non-redundant component of a Protection System events because it makes Table 1 clearer to read, understand and differentiate between what is required of these events compared to other Extreme Events.

Table 1 – Steady State & Stability Performance Planning Events
Steady State & Stability (all events): a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur. b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0. c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event. d. Simulate Normal Clearing unless otherwise specified. e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings. **Steady State Only (P0 through P7 events only)**: f. Applicable Facility Ratings shall not be exceeded. g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner. h. Planning event P0 is applicable to steady state only. i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements. **Stability Only (P1 through P7 events only):** j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P8 Multiple Contingency *(Fault plus non-redundant component of a Protection System failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	3Ø	EHV, HV	Yes	Yes

5. Do you agree with the drafting team's approach which doesn't add additional applicable entities to the applicability of the standard? (e.g. RC, Transmission Operator (TO), Generator Operator (GO), Distribution Provider (DP))

☒ Yes
☐ No

Comments:

6. Do you agree with the 36 month implementation period to address All Requirements except for Requirement R4, Part 4.6, and Requirement 2, Part 2.7 associated with P5 due to Footnote 13 bullets 2, 3 and 4, as well as the definitions?

☒ Yes
☐ No

Comments:

7. Do you agree with the 60 month implementation plan for Requirement 4, Part 4.6 and Requirement 2, Part 2.7 associated with P5 due to Footnote 13 bullets 2, 3 and 4?

☐ Yes
☒ No

Comments:

There is a concern that utilities will not be able to meet the 60 month implementation plan in a reliabile manner. Unlike other potential areas identified in Planning Studies where the system may not meet the System Performance Requirements outlined in Table 1, other temporary reliable solutions, such as the use of Operating Procedures, are available that can be implemented until a long term solution (capital project) is completed. In many instances the only way to fully mitigate impacts resulting from "failure of a non-redundant component of a Protection System" event is to add redundancy. If this cannot be achieved in 60 months utilities may be forced to make undesirable system protection adjustments that could result in a higher rate of misoperations, reduction of system security, and reduced reliability until redundancy can be added. This should not be interpreted as utlities ignoring the importance of adding redundancy at critical points on the system, but implementation should be done on a cost/benefit (risk assessment) basis that takes into consideration the resources individual utilities have to adequately address areas of concerns resulting form single points of failure. In other words, the timing requirement of the implementation plan should not be so prescriptive that it leads to greater reliability risks than the conerns associated with the potential consequences of a single point of failure event.

8. Are you aware of any other governing documents that could be in conflict with the current proposal for this draft of the standard?

☐ Yes
☒ No

Comments:

9. Do you agree with the teams proposed changes to align the VRF/VSLs for Requirement 4, Part 4.6 with the VRF/VSLs for Requirement 2, Part 2.7?

☒ Yes
☐ No

Comments:

10. Do you have any other general recommendations/considerations for the drafting team?

☒ Yes
☐ No

Comments:

WAPA believes there is risk with the proposed changes of the single point of failure (SPF) language that will not significantly improve reliability. There is likelihood this change may even reduce reliability by having the CAPs force entities to redirect its limited resources away from other important reliability needs to solve SPF identified issue. Further, implementation of the CAPs may likely cause significant mis-ops while system protection systems are being modified to eliminate SPFs thus reducing reliability and increase risk to the transmission system.

Frequency of these SPF events are so seldom, they do not warrant the cost to eliminate unless there are significant risks to the transmission system such as instability and cascading. No data has been provided to demonstrate that SPFs have been a significant factor in system outages.

Table A: Criteria for Buses to be Tested
Buses operated at 200 kV or higher with 4 or more circuits
Buses operated at 100 kV to 200 kV with 6 or more circuits
Buses operated at 100 kV or higher that directly supply off-site power to a nuclear generating station
Any additional buses operated at 100 kV or higher that the Transmission Planner believes are necessary for the reliable operation of the bulk power system

Table C: Performance Measures
1. Loss of synchronism of generating units totaling greater than 2,000 MW or more in the Eastern Interconnection or Western Interconnection, or 1,000 MW or more in the ERCOT or Québec Interconnections
2. Loss of synchronism between two portions of the system
3. Negatively damped oscillations