Comment Report

Project Name:	Project 2015-10 Single Points of Failure | TPL-001-5
Comment Period Start Date:	9/8/2017
Comment Period End Date:	10/23/2017
Associated Ballots:	2015-10 Single Points of Failure TPL-001-5 IN 1 ST

There were 70 sets of responses, including comments from approximately 192 different people from approximately 118 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree that an associated timetable for implementation of actions needed to prevent the System from Cascading (TPL-001-5 Requirement R4, Part 4.2.2.1) and an annual review of implementation status (TPL-001-5 Requirement R4, Part 4.2.2.2) should be required when analysis concludes there is Cascading caused by the occurrence of extreme events 2e-2h in the stability column?

2. Do you agree that the requirements of the proposed TPL-001-5 Requirement R4, Parts 4.2.2.1 and 4.2.2.2, including an implementation timetable and annual review of implementation status, should not and do not mandate actual implementation of actions identified as needed to prevent the System from Cascading? For example, do you agree that a capital project is not required to be implemented by Requirement R4, Parts 4.2.2.1 and 4.2.2.2, even if the capital project is the only feasible action available to prevent the System from Cascading when analysis concludes there is Cascading caused by the occurrence of extreme events 2e-2h in the stability column?

3. Do you agree with the omission, as proposed in TPL-001-5 Requirement R4, Part 4.2, of a requirement similar to that of Requirement R2, Part 2.7, which states that the planned System shall continue to meet the performance requirements in Table 1 in subsequent Planning Assessments?

4. Do you agree with including Table 1 Footnote 13 a., "[a] single protective relay which responds to electrical quantities, without an alternative that provides comparable Normal Clearing times, *e.g.*, sudden pressure relaying", and its limitation to only the specific single protective relay and not to other elements of the associated Protection System?

5. Do you agree with the inclusion of Table 1 Footnote 13 b. & c. stipulation, "which is not monitored or not reported", and that it conveys the expectation that the monitoring and reporting is sufficient to result in prompt remediation addressing the failure status of the associated equipment?

6. Do you agree with the inclusion of Table 1 Footnote 13 d., and that it, in conjunction with defined terms, identifies what constitutes all of the elements of, "A single control circuitry associated with protective functions including the trip coil(s) of the circuit breakers or other interrupting devices."?

7. Do you agree with the proposed changes to Requirement 1, Part 1.1.2 that modify which known outages shall be represented in System models from those "with a duration of at least six months" to those selected by the Planning Coordinator (PC)/Transmission Planner (TP) "in consultation with" their Reliability Coordinators (RCs).

8. Do you agree with omitting the Reliability Coordinator (RC) from the applicability of the TPL-001-5 standard given that Requirement R1, Part1.1.2 requires consultation between the TP/PC and the RC to determine which known outages to select for representation in System models?

9. FERC Order No. 786 Paragraphs 40-45 direct modification to address significant planned maintenance outages with durations less than 6 months in planning assessments. Are you aware of an existing standard/requirement, consistent with industry practice and applicability that requires review and coordination of significant known maintenance outages less than 6 months in duration for inclusion in System models (TPL 001-4 Requirement R1 Part R1.1.2)?

10. Do you agree with the 36 month implementation period to address all Requirements except for Requirement R4, Part 4.2, and Requirement 2, Part 2.7 associated with the modified P5 events further defined in the redline changes to Footnote 13.

11. Do you agree with the 60 month implementation plan for Requirement 4, Part 4.2 and Requirement 2, Part 2.7 associated with the modified P5 events further defined in the redline changes to Footnote 13.?

12. In looking at all proposed recommendations from the standard drafting team, are the proposed changes a cost effective approach which meets the FERC directives? (*see Cost Effectiveness Background Document*)

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

14. 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
Brandon McCormick	Brandon McCormick		FRCC	FMPA	Tim Beyrle	City of New Smyrna Beach Utilities Commission	4	FRCC
					Jim Howard	Lakeland Electric	5	FRCC
					Lynne Mila	City of Clewiston	4	FRCC
					Javier Cisneros	Fort Pierce Utilities Authority	3	FRCC
					Randy Hahn	Ocala Utility Services	3	FRCC
					Don Cuevas	Beaches Energy Services	1	FRCC
					Jeffrey Partington	Keys Energy Services	4	FRCC
					Tom Reedy	Florida Municipal Power Pool	6	FRCC
					Steven Lancaster	Beaches Energy Services	3	FRCC
					Mike Blough	Kissimmee Utility Authority	5	FRCC
					Chris Adkins	City of Leesburg	3	FRCC
					Ginny Beigel	City of Vero Beach	3	FRCC
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

					Shari Heino	Brazos Electric Power Cooperative, Inc.	1,5	Texas RE
					Ginger Mercier	Prairie Power, Inc.	1,3	SERC
					John Shaver	Arizona Electric Power Cooperative, Inc.	1	WECC
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
MRO	Dana Klem	1,2,3,4,5,6	MRO	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
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administration	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 Powert	1,5	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Tom Breene	Wisconsin Public Service Corporation	3,5,6	MRO
					Jeremy Voll	Basin Electric Power Cooperative	1	MRO
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO

					Mike Morrow	Midcontinent ISO	2	MRO
Tennessee Valley Authority	Dennis Chastain	1,3,5,6	SERC	Tennessee Valley Authority	DeWayne Scott	Tennessee Valley Authority	1	SERC
					Ian Grant	Tennessee Valley Authority	3	SERC
					Brandy Spraker	Tennessee Valley Authority	5	SERC
					Marjorie Parsons	Tennessee Valley Authority	6	SERC
Electric Reliability Council of Texas, Inc.	Elizabeth Axson	2		IRC Standards Review Committee	Elizabeth Axson	ERCOT	2	Texas RE
					Ben Li	IESO	2	NPCC
					Mark Holman	PJM	2	RF
					Greg Campoli	NYISO	2	NPCC
					Terry BIlke	Midcontinent ISO, Inc.	2	MRO
					Ali Miremadi	California ISO	2	WECC
					Matthew Goldberg	ISO NE	2	NPCC
					Charles Yeung	Southwest Power Pool, Inc. (RTO)	2	SPP RE
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
Public Utility District No. 1 of Chelan County	Haley Sousa	5		Chelan PUD	Janis Weddle	Public Utility District No. 1 of Chelan County	6	WECC
					Joyce Gundry	Public Utility District No. 1 of Chelan County	3	WECC
					Jeff Kimbell	Public Utility District No. 1 of Chelan County	1	WECC
					Haley Sousa	Public Utility District No. 1 of Chelan County	5	WECC
JEA	Joe McClung	1,3,5	FRCC	JEA Voters	Ted Hobson	JEA	1	FRCC
					Garry Baker	JEA	3	FRCC
					John Babik	JEA	5	FRCC
Associated Electric Cooperative, Inc.	Mark Riley	1		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		LCRA Compliance	Teresa Cantwell	LCRA	1	Texas RE
					Dixie Wells	LCRA	5	Texas RE
					Michael Shaw	LCRA	6	Texas RE
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Katherine Prewitt	Southern Company Services, Inc.	1	SERC
					R. Scott Moore	Alabama Power Company	3	SERC
					William D. Shultz	Southern Company Generation	5	SERC

					Jennifer G. Sykes	Southern Company Generation and Energy Marketing	6	SERC
BC Hydro and Power Authority	Patricia Robertson	1,3,5		BC Hydro	Patricia Robertson	BC Hydro and Power Authority	1	WECC
					Venkataramakrishnan Vinnakota	BC Hydro and Power Authority	2	WECC
					Pat G. Harrington	BC Hydro and Power Authority	3	WECC
					Clement Ma	BC Hydro and Power Authority	5	WECC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no Dominion	Guy V. Zito	Northeast Power Coordinating Council	10	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
					Laura Mcleod	NB Power	1	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
					Kathleen Goodman	ISO-NE	2	NPCC
					Greg Campoli	NYISO	2	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	6	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
					Sylvain Clermont	Hydro Quebec	1	NPCC
					Helen Lainis	IESO	2	NPCC
					Chantal Mazza	Hydro Quebec	2	NPCC
					Michael Forte	Con Ed	1	NPCC
					Daniel Grinkevich	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Brian O'Boyle	Con Ed	5	NPCC
Scott Miller	Scott Miller		SERC	MEAG Power	Roger Brand	MEAG Power	3	SERC
					David Weekley	MEAG Power	1	SERC
					Steven Grego	MEAG Power	5	SERC
Dominion - Dominion Resources, Inc.	Sean Bodkin	6		Dominion	Connie Lowe	Dominion - Dominion Resources, Inc.	3	NA - Not Applicable
					Lou Oberski	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable

					Larry Nash	Dominion - Dominion Virginia Power	1	NA - Not Applicable
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					Jim Nail	City of Independence, Power and Light Department	5	SPP RE
					Louis Guidry	Cleco Corporation	1,3,5,6	SPP RE
					Tara Lightner	Sunflower Electric Power Corporation	1	SPP RE
					Mike Kidwell	Empire District	1,3,5	SPP RE

1. Do you agree that an associated timetable for implementation of actions needed to prevent the System from Cascading (TPL-001-5 Requirement R4, Part 4.2.2.1) and an annual review of implementation status (TPL-001-5 Requirement R4, Part 4.2.2.2) should be required when analysis concludes there is Cascading caused by the occurrence of extreme events 2e-2h in the stability column?

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

Answer	No
Document Name	

Comment

SCL does not agree with the implementation of corrective action plan and the requirement for an annual review of the implementation status when analysis concludes there is Cascading caused by extreme events. Implementing actions for extreme events can be costly, and may not produce much benefit because of the low frequency of these types of events happening.

Likes 0	
Dislikes 0	

Response

Mike Smith - Manitoba Hydro - 1

Answer	No
Document Name	

Comment

Requirement 4.2.2 NERC requires listing of possible actions, which is ok. However, 4.2.2.1 requires a timetable for implementation. In the past, the decision to mitigate extreme events has been left to the discretion of the Planning Coordinator. The PC is best able to set their risk tolerance or do a cost/benefit analysis to determine whether the Corrective Action Plan should be implemented. If the PC has no plans to implement the corrective action plan then why does a timetable need to determined and followed up in subsequent assessments.

Likes 1	Manitoba Hydro , 5, Xiao Yuguang
Dislikes 0	

Response

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

For extreme contingencies, SRP believes awareness of the impacts and the associated actions required to prevent the System from Cascading are sufficient. SRP recommends removing the the following language from 4.2.2.1. “and the associated timetable for implementation”	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
Dominion Energy does not see any value added in extending the requirement to include event categories 2e-2h.	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts	
Answer	No
Document Name	
Comment	
AECI contends that extreme events are simulated for informational purposes and development of actions needed to prevent the system from cascading should not be mandated, but should rather be left to the PC’s and TP’s judgement.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

BPA does not agree with separating out extreme events in 2e-2h for mitigation, everything should be included in 4.2.1. BPA suggests removing any reference to implementation status and timetables. BPA suggests only including requirements for performing studies to assess the impact, analyzing the results and evaluating possible actions to reduce the likelihood or mitigate the consequences of extreme events.

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 - 5

Answer	No
Document Name	

Comment

AEP disagrees. These proposed subrequirements exceed the authorization of the SAR. They attempt to convert certain extreme category events involving failure of a non-redundant component of a protection system into quasi-planning events where cascading is to be prevented (though while other performance requirements on consequential load loss, exceeding facility ratings, voltage deviations, etc., are omitted). In addition, AEP questions the benefit of devising preventive actions and an associated timetable, and performing an annual review of implementation status for mitigating actions that are supposedly never to be "required."

Likes 0	
Dislikes 0	

Response

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6

Answer	No
Document Name	

Comment

In the past, the decision to mitigate extreme events has been left to the discretion of the Planning Coordinator. The TP is best able to set their risk tolerance or do a cost/benefit analysis to determine whether the Corrective Action Plan should be implemented. If the TP has no plans to implement the corrective action plan then why does a timetable need to be determined and followed up on in subsequent assessments.

Likes 0	
Dislikes 0	

Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	No
Document Name	
Comment	

AZPS does not support the inclusion of Parts 4.2.2, 4.2.2.1, and 4.2.2.2. It is AZPS's understanding that, based on previous stakeholder input, the SDT determined that a Corrective Action Program (CAP) requirement was not appropriate for these extreme contingencies. AZPS respectfully submits that, although the verbiage has been revised, the obligation on entities as a result of Parts 4.2.2, 4.2.2.1, and 4.2.2.2 essentially amounts to a CAP requirement. In fact, AZPS reads the requirements of Parts 4.2.2, 4.2.2.1, and 4.2.2.2 as providing an even more rigorous obligation than other CAP requirements. For example, in Requirement R2.8, the CAP requires 3 actions: (1) a list of deficiencies, (2) the actions necessary to address these, and (3) an annual review for continued validity and status. Parts 4.2.2, 4.2.2.1, and 4.2.2.2 require: (1) a list of deficiencies, (2) the actions necessary to address these, (3) a timetable for implementation, and (4) annual review for continued validity and status. Thus, in comparing requirements for a CAP and the requirements set forth in Parts 4.2.2, 4.2.2.1, and 4.2.2.2, it is clear that, despite stakeholder input, Parts 4.2.2, 4.2.2.1, and 4.2.2.2 are still requiring a CAP even though the contingencies to be addressed are extreme, unlikely to occur, difficult and expensive to address, and unlikely to significantly improve reliability. Finally, AZPS respectfully suggests that it is not cost effective to attempt to resolve system efficiencies as a result of such extreme events. Such activities have a very low cost/benefit ratio, and will result in the unnecessary expenditure of resources by registered entities. For these reasons, AZPS cannot support the inclusion of Parts 4.2.2, 4.2.2.1, and 4.2.2.2 and, therefore, cannot support an associated timetable for implementation or annual review of implementations status. AZPS recommends the deletion of Parts 4.2.2, 4.2.2.1, and 4.2.2.2 from TPL-001-5.

If Parts 4.2.2, 4.2.2.1, and 4.2.2.2 are not removed as requested above, AZPS submits the following suggested language:

4.2.2 If the analysis concludes there is Cascading caused by the occurrence of extreme events 2e -2h and/or the PC shall: stability co

4.2.2.1 Document the list of System deficiencies and actions that could be taken to prevent the System from Cascading.
4.2.2.2 Review the list of System Deficiencies and potential actions to address such System deficiencies in subsequent annual Planning Assessments for continued validity

Likes 0	
Dislikes 0	
Response	
Joe McClung - JEA - 1,3,5 - FRCC, Group Name JEA Voters	
Answer	No
Document Name	
Comment	

JEA appreciates the effort of the SDT addressing the directives from the Commission on Order No. 786 as well as the recommendation from the SPCS and the SAMS from the assessment of protection system single points of failure in response to Order No. 754. 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 4.2.2, subparts 4.2.2.1 and 4.2.2.2 go beyond the recommendation from the Section 1600 Data Request report for Order No. 754. The issue of 'Cascading caused by the occurance of extreme events' is already addressed by part 4.2.1 that 'an evaluation of possible actions designated to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.' Besides, a Cascading caused by the extreme event due to protection system single points of failure (Table 1 Extreme Events – Stability 2e-2h) is no different than a Cascading due to any other extreme event (Table 1 Extreme Events – Stability 2a-2d, 2i-2j) - 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.

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.

Suggestion: Part 4.2.2, subparts 4.2.2.1 and 4.2.2.2 of the Requirement 4 is not needed as the issue of Cascading due to the extreme events is already covered by Part 4.2.1. Delete "excluding extreme events 2e-2h in the stability column" from Part 4.2.1 and it will cover ALL the Cascading due to extreme events

Likes 2	JEA, 5, Babik John; Seminole Electric Cooperative, Inc., 1,3,4,5,6, Ward Kristine
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Xcel Energy recommends that the Standard Drafting Team remove the timetable language and change the language similar to Requirement 4, part 4.2.1 to state "an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted."

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	No
Document Name	
Comment	
We believe a three-phase fault including protection system failure would have an extremely low probability of occurring. Requiring implementation of actions to prevent these extremely rare events would cause a large and unnecessary financial burden with little benefit to our system reliability.	
Likes 0	
Dislikes 0	
Response	

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins	
Answer	No
Document Name	
Comment	
NVE does not agree that an implementation plan with a timetable should be created for a subset of extreme events. Given the low probability of extreme events, NVE suggests only including the requirements for performing studies to analyze the results, assess the impacts and evaluate possible actions to reduce the likelihood or mitigate the consequences of extreme events. Additionally, the wording in R4.2.1 is nearly identical to the wording in the last sentence in R4.5. NVE suggest moving R4.2.1 – R4.2.2.2 and incorporating it into R4.5	
Likes 0	
Dislikes 0	
Response	

ALAN ADAMSON - New York State Reliability Council - 10	
Answer	No
Document Name	
Comment	
Part 4.2.2 of TPL-001-5 implies a requirement to implement actions to prevent the System from Cascading caused by extreme events, a criterion beyond the basic design and planning criteria. This requirement essentially moves such events into the “Steady State & Stability Performance Planning Events” table and a consideration for R2, R3 and R4 for which any unacceptable performance will require actions to mitigate the risks/reliability impacts. This is contrary to the intent of listing the 2a to 2j events under the Extreme Event table. We objected to the previous draft TPL-001 revision because it called for a Corrective Action Plan (CAP) to avoid or mitigate such reliability impacts. Although this new draft standard removed a specific CAP requirement, it appears that this revised version continues to require implementation of actions to mitigate or avoid Cascading due to low probability	

extreme events, no matter the cost. We have no issue with requiring an evaluation of possible actions needed to prevent the System from Cascading, but we do object to a further requirement to implement an action or actions without considering cost and other factors.	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	No
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. We would also like to point out that there is no corresponding directive from FERC in the SAR.	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Suggest that Part 4.2.2 and its sub Parts can be struck. If there is a corrective action plan required, as implied by 4.2.2.1, then this event should be listed in Table 1 P5 instead of the Extreme Event Table. Also, in 4.2.1, strike the phrase “excluding extreme events 2e – 2h in the stability column”. The strategy to manage extreme events should be the same for all categories of extreme events – and as such, the requirements in 4.2.1 (i.e., evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the events(s) shall be conducted) is sufficient.	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	No

Document Name	
Comment	
No. Question 1 and the referenced standard language state that a CAP is required but Question 2 implies that implementation of the CAP is not required. The SDT should consider clarifying how implementation status will be reviewed when no implementation is actually required. This lack of clarity may lead to inconsistent interpretation by Registered Entities as well as Regional Entities on what constitutes compliance.	
Likes 0	
Dislikes 0	
Response	
Lynn Goldstein - PNM Resources - Public Service Company of New Mexico - 1,3	
Answer	No
Document Name	
Comment	
I support PNM's comments.	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	No
Document Name	
Comment	
FMPA agrees with JEA's comments	
Likes 1	Seminole Electric Cooperative, Inc., 1,3,4,5,6, Ward Kristine
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	

Answer	No
Document Name	
Comment	

Although the drafting team made its rationale clear for including a requirement for entities to document an associated timetable and perform annual reviews for the extreme events 2e-2h that result in cascading, SCE advocates that this language confuses the intent and will create compliance ambiguity in the future. SCE proposes that the drafting team remove sub-requirement R4.2.1 and R4.2.2 (and the underlying R4.2.2.1 & R4.2.2.2) entirely. This change will significantly reduce the confusion for the intention to not obligate entities to actually implement actions identified, and it will keep the compliance obligation clear in the future. Entities should look into actions that may reduce exposure or impact for 2e-2h in the same manner as other extreme events. Requiring a timetable without an obligation to implement does not add value to system planning.

Likes 0	
Dislikes 0	
Response	

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer	No
Document Name	
Comment	

Please see comments submitted by Robert Blackne

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 wording in Requirement R4, Parts 4.2.2.1 and 4.2.2.2 related to implementation. The wording related to implementation could be interpreted as requiring the actual implementation of actions identified as being needed to prevent the System from Cascading. Additionally, the wording related to implementation may be inconsistent with other provisions in TPL-001-5. Requirement R3, Part 3.5 has a similar identification and listing requirement regarding extreme events in the steady state portion of the Planning Assessment. However, there is no wording related to implementation in Requirement R3, Part 3.5.CenterPoint Energy recommends wording for Parts 4.2.2.1 and 4.2.2.2 be similar to Requirement R3, Part 3.5 and that references to implementation be removed.

CenterPoint Energy recommends that Parts 4.2.2.1 and 4.2.2.2 be revised as follows:

4.2.2.1. List System deficiencies and the associated actions needed to prevent the System from Cascading.

4.2.2.2. Be reviewed in subsequent annual Planning Assessments for continued validity.

Likes 0	
Dislikes 0	

Response

Robert Ganley - Long Island Power Authority - 1

Answer	No
Document Name	

Comment

We do not agree with adding Parts 4.2.2.1 and 4.2.2.2 as they imply requiring implementation of actions needed to prevent the System from Cascading caused by extreme events – a criterion beyond the basic design and planning criteria. Adding these two parts essentially moves them into the “Steady State & Stability Performance Planning Events” table and a consideration for R2, R3 and R4 for which any unacceptable performance will require actions to mitigate the risks/reliability impacts. This is contrary to the intent of listin g the 2a to 2j events under the Extreme Event table.

We strongly recommend the SDT to revert R4 to the currently approved version (TPL-001-4).

Additional Comment for consideration, related to Requirement #4 (related to clarification of the Standard):

Requirement 4.1 states that “Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1…..” Immediately after 4.1, sub-requirements 4.1.1 through 4.1.3 specify specific system/generator stability performance requirements which are not mentioned in Table 1. Our observation is that Table 1 includes steady state and stability related performance requirements. This apparent placement of performance requirements in more than one location within the Standard document is confusing. Recommendation for consideration is to move sub-requirements 4.1.1 through 4.1.3 to Table 1.

Likes 0	
Dislikes 0	

Response

Ellen Oswald - Midcontinent ISO, Inc. - 2

Answer	No
Document Name	

Comment

This overcomplicates the standard. The purpose of extreme event analysis is to understand the potential consequences of extreme events and to develop some ideas on how to address extreme events that result in cascading or instability. However, the current standard stops short of requiring corrective action plans, but defers to the PC/TP to make that determination based on the i) probability of occurrence, ii) level of impact, and iii) cost to mitigate or remedy. On the other hand, the purpose of planning contingencies (P1-P7) is to dictate minimum performance standards and require corrective action plans if performance does not meet the requirements of the standard. This clear distinction between planning contingencies and extreme event contingencies should be maintained for clarity and to avoid confusion. Therefore, to the extent it is desirable to modify the TPL standard to require corrective action plans for certain extreme events under certain situations, it would be better to move such events into the planning contingency category. That is, if it is desirable to require that corrective action plans be developed for three-phase faults with delayed clearing due to protection system failure if such events cause cascading or instability, then a P8 contingency should be created for this purpose, thus moving the three-phase fault with delay clearing out of the extreme event category and into the planning event category.   This maintains a clear distinction between extreme events and planning events.

Likes 0	
Dislikes 0	
Response	
Payam Farahbakhsh - Hydro One Networks, Inc. - 1	
Answer	No
Document Name	
Comment	

We would agree if the Standard Drafting Team would make it clear whether an implementation of a Corrective Action Plan is mandated in the Standard for Requirement R4, Part 4.2.2. While we agree that all mandated Corrective Action Plans (NERC defined term) should have an associated timetable for implementation (and possibly annual review of its status), we do not agree with requiring a timetable for implementation actions and annual review of implementation status if the Corrective Action Plan is not mandated.

If the Standard Drafting Team intends for these actions to be implemented, we will recommend using “Corrective Action Plan”, which is a NERC defined term and eliminates the ambiguity in the requirement.

Likes 1	Hydro One Networks, Inc., 3, Malozewski Paul
Dislikes 0	
Response	
Greg Davis - Greg Davis On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Greg Davis	
Answer	No
Document Name	
Comment	

GTC does not support the inclusion of Parts 4.2.2, 4.2.2.1, and 4.2.2.2, for similar reasons to AZPS:

It is AZPS's understanding that, based on previous stakeholder input, the SDT determined that a Corrective Action Program (CAP) requirement was not appropriate for these extreme contingencies. AZPS respectfully submits that, although the verbiage has been revised, the obligation on entities as a result of Parts 4.2.2, 4.2.2.1, and 4.2.2.2 essentially amounts to a CAP requirement. In fact, AZPS reads the requirements of Parts 4.2.2, 4.2.2.1, and 4.2.2.2 as providing an even more rigorous obligation than other CAP requirements. For example, in Requirement R2.8, the CAP requires 3 actions: (1) a list of deficiencies, (2) the actions necessary to address these, and (3) an annual review for continued validity and status. Parts 4.2.2, 4.2.2.1, and 4.2.2.2 require: (1) a list of deficiencies, (2) the actions necessary to address these, (3) a timetable for implementation, and (4) annual review for continued validity and status. Thus, in comparing requirements for a CAP and the requirements set forth in Parts 4.2.2, 4.2.2.1, and 4.2.2.2, it is clear that, despite stakeholder input, Parts 4.2.2, 4.2.2.1, and 4.2.2.2 are still requiring a CAP even though the contingencies to be addressed are extreme, unlikely to occur, difficult and expensive to address, and unlikely to significantly improve reliability. Finally, AZPS respectfully suggests that it is not cost effective to attempt to resolve system efficiencies as a result of such extreme events. Such activities have a very low cost/benefit ratio, and will result in the unnecessary expenditure of resources by registered entities. For these reasons, AZPS cannot support the inclusion of Parts 4.2.2, 4.2.2.1, and 4.2.2.2 and, therefore, cannot support an associated timetable for implementation or annual review of implementations status

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 disagrees with the use of the term "implementation" in 4.2.2.1 and 4.2.2.2. Currently as written, a Planner is only required to conduct an evaluation of possible actions to reduce likelihood of Cascading resulting from extreme events. There is no further requirement for additional action other than what the evaluation must be comprised of. The use of the term "implementation" implies that an action other than the evaluation is required. The drafting team should consider adding additional language stating that implementation of said actions, are at the discretion of the Planner.

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

The term “Planning Assessment” is defined in the NERC Glossary as a “documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies.” We believe these studies should not be used as a tracking mechanism for Corrective Action Plans, and that an adjustable time frame should be considered during subsequent reviews.	
Likes 0	
Dislikes 0	
Response	
John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson	
Answer	No
Document Name	
Comment	
ISO-NE does not believe that it is appropriate to require the development of a timetable for implementation of a corrective action plan to address extreme events. Additionally, an annual review of the implementation status should not be required for extreme events.	
Likes 0	
Dislikes 0	
Response	
Gary Trent - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	No
Document Name	
Comment	
Extreme events should not need mitigation so a timetable is not needed.	
Likes 0	
Dislikes 0	
Response	
Haley Sousa - Public Utility District No. 1 of Chelan County - 5, Group Name Chelan PUD	
Answer	No
Document Name	
Comment	

CHPD does not agree with implementing a corrective action plan or an annual review of implementation status for preventing Cascading for Extreme Events. Extreme Events have a low likelihood of occurring and to mitigate these types of events would be costly and not provide much benefit due to their low likelihood of happening. The reference to a timetable, without a requirement to actually implement, may additionally provide a source of confusion. As an example, if a project would be needed seven years into the future, would it be appropriate for the timetable to reflect this seven year deadline, or should it reflect the system changes required to meet the seven year deadline? As a second example, if based on this analysis, system changes are immediately required to prevent Cascading, what should this timeframe reflect?

The second point of confusion is the language referencing the word “action”. Action is an undefined term, and thus is subject to multiple potential interpretations. Is the reference to action to mean that manual operator action is acceptable, or does action refer to a capital project to enact system changes to prevent the Cascading? This is unclear based on NERC and industry dialogue on this point.

The current language in TPL-001-4 only references an evaluation of possible **actions** designed to reduce the likelihood **or** mitigate the consequences of the event, not to determine a system change to fully mitigate the Cascading. There are two changes in the new proposed standard – the first is that the Cascading MUST have a fully mitigated solution (whereas the previous version also allowed a reduction of the likelihood) and the previous standard’s wording of action seemed to indicate the use of operator action, whereas the new standard’s discussion of timetables and implementation status is more consistent with the definition of action associated with the required system changes under the Corrective Action Plans.

Likes 0	
Dislikes 0	

Response

Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw

Answer	No
Document Name	

Comment

The extreme events 2e-2h involve three-phase faults with delayed clearing. Three-phase faults are considered uncommon and very unlikely. If this involved single-phase faults with delayed clearing, then Oncor could agree with an associate time table since they are more probabilistic and feasible in terms of a capital project. The probability of a 3 phase fault along with delayed clearing of the fault is extremely unlikely. Additionally, an occurrence of this magnitude will generally involve shedding load and isolating the rest of the fault from the system.

Likes 0	
Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 3

Answer	No
Document Name	

Comment

We believe that the proposed changes are confusing. It appears that the addition of part 4.2.2 requires a fix to prevent cascading for extreme events caused by non-redundant relaying components, while part 4.2.1 would continue to allow cascading for stuck breaker conditions. Why does part 4.2.2 require fixes for failure of non-redundant relaying components? Why isn't this requirement part of the PRC standards, but is instead proposed for standard TPL-001?	
Likes 0	
Dislikes 0	
Response	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3	
Answer	No
Document Name	
Comment	
CHPD does not agree with implementing a corrective action plan or an annual review of implementation status for preventing Cascading for Extreme Events. Extreme Events have a low likelihood of occurring and to mitigate these types of events would be costly and not provide much benefit due to their low likelihood of happening. The reference to a timetable, without a requirement to actually implement, may additionally provide a source of confusion. As an example, if a project would be needed seven years into the future, would it be appropriate for the timetable to reflect this seven year deadline, or should it reflect the system changes required to meet the seven year deadline? As a second example, if based on this analysis, system changes are immediately required to prevent Cascading, what should this timeframe reflect? The second point of confusion is the language referencing the word “action”. Action is an undefined term, and thus is subject to multiple potential interpretations. Is the reference to action to mean that manual operator action is acceptable, or does action refer to a capital project to enact system changes to prevent the Cascading? This is unclear based on NERC and industry dialogue on this point. The current language in TPL-001-4 only references an evaluation of possible **actions** designed to reduce the likelihood **or** mitigate the consequences of the event, not to determine a system change to fully mitigate the Cascading. There are two changes in the new proposed standard – the first is that the Cascading MUST have a fully mitigated solution (whereas the previous version also allowed a reduction of the likelihood) and the previous standard’s wording of action seemed to indicate the use of operator action, whereas the new standard’s discussion of timetables and implementation status is more consistent with the definition of action associated with the required system changes under the Corrective Action Plans.	
Likes 0	
Dislikes 0	
Response	
Janis Weddle - Public Utility District No. 1 of Chelan County - 6	
Answer	No
Document Name	
Comment	

CHPD does not agree with implementing a corrective action plan or an annual review of implementation status for preventing Cascading for Extreme Events. Extreme Events have a low likelihood of occurring and to mitigate these types of events would be costly and not provide much benefit due to their low likelihood of happening. The reference to a timetable, without a requirement to actually implement, may additionally provide a source of confusion. As an example, if a project would be needed seven years into the future, would it be appropriate for the timetable to reflect this seven year deadline, or should it reflect the system changes required to meet the seven year deadline? As a second example, if based on this analysis, system changes are immediately required to prevent Cascading, what should this timeframe reflect?

The second point of confusion is the language referencing the word “action”. Action is an undefined term, and thus is subject to multiple potential interpretations. Is the reference to action to mean that manual operator action is acceptable, or does action refer to a capital project to enact system changes to prevent the Cascading? This is unclear based on NERC and industry dialogue on this point.

The current language in TPL-001-4 only references an evaluation of possible **actions** designed to reduce the likelihood **or** mitigate the consequences of the event, not to determine a system change to fully mitigate the Cascading. There are two changes in the new proposed standard – the first is that the Cascading MUST have a fully mitigated solution (whereas the previous version also allowed a reduction of the likelihood) and the previous standard’s wording of action seemed to indicate the use of operator action, whereas the new standard’s discussion of timetables and implementation status is more consistent with the definition of action associated with the required system changes under the Corrective Action Plans.

Likes 0	
Dislikes 0	

Response

Long Duong - Public Utility District No. 1 of Snohomish County - 1

Answer	Yes
Document Name	

Comment

SNPD does not have additional comments.

Likes 0	
Dislikes 0	

Response

Kevin Giles - Westar Energy - 1

Answer	Yes
Document Name	

Comment

Westar agrees with the the SPP Standards Review Group to recommend that the drafting team adds language to section 4.2.2.2 to clarify during the review process pertaining to the Planning Assessments for continued validity and implementation status that an adjustable time frame would always be taken into consideration.

Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
ITC concurs with R4 and the extreme events 2e-2h but believes that shunts should be added to the list of extreme events.	
Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
The review should follow the designated Transmission Planner's existing processes that have already been developed. This review should be rolled into that process.	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
In general we do not agree with imposing Corrective Action Plan requirement to prevent Cascading caused by extreme events, as it is a criterion beyond the basic design and planning criteria. However, we do agree with adding Parts 4.2.2.1 and 4.2.2.2 and require implementation of corrective action plans to mitigate reliability risks caused by failure of non-redundant Protection System components (only if the simulation indicates Cascading). Both FERC's Order 754 and NERC's Protection	

Systems Single Point of Failure - White Paper establish an event consisting of a three-phase fault followed by the failure of a non-redundant protection system component as a reliability concern that needs to be addressed. Moreover, the NPCC members have been mitigating these types of events for decades now, through the implementation of NPCC's regional criteria. Thus we strongly believe this should be a continent-wide requirement, as it helps improve the system's overall reliability.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Since the requirements state there should be actions needed to prevent the system from Cascading and a timetable for implementation, Texas RE recommends requiring a Corrective Action Plan, which the NERC Glossary states is "A list of actions and an associated timetable for implementation to remedy a specific problem."	
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 adds language to section 4.2.2.2 to clarify during the review process pertaining to the Planning Assessments for continued validity and implementation status that an adjustable time frame would always be taken into consideration.	
Likes 0	
Dislikes 0	
Response	
John Seelke - LS Power Transmission, LLC - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

James Anderson - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 4	
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	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Fred Frederick - Southern Indiana Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1,5, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5	
Answer	
Document Name	
Comment	
Please see comments of Joe O'Brien NIPSCO.	
Likes 0	
Dislikes 0	
Response	

Steve Toosevich - NiSource - Northern Indiana Public Service Co. - 1	
Answer	
Document Name	
Comment	
See Joe O'Brien Comments for NIPSCO.	
Likes 0	
Dislikes 0	
Response	

Scott Miller - Scott Miller On Behalf of: David Weekley, MEAG Power, 3, 5, 1; Roger Brand, MEAG Power, 3, 5, 1; Steven Grego, MEAG Power, 3, 5, 1; - Scott Miller, Group Name MEAG Power	
Answer	
Document Name	
Comment	
MEAG Power supports the comments of Southern Company Services.	
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 Dominion	
Answer	

Document Name	
Comment	

In general we do not agree with imposing Corrective Action Plan requirement to prevent Cascading caused by extreme events, as it is a criterion beyond the basic design and planning criteria.

However, we do agree with adding Parts 4.2.2.1 and 4.2.2.2 and require implementation of corrective action plans to mitigate reliability risks caused by failure of non-redundant Protection System components (only if the simulation indicates Cascading). Both FERC's Order 754 and NERC's Protection Systems Single Point of Failure - White Paper establish an event consisting of a three-phase fault followed by the failure of a non-redundant protection system component as a reliability concern that needs to be addressed. Moreover, the NPCC members have been mitigating these types of events for decades now, through the implementation of NPCC's regional criteria. Thus we strongly believe this should be a continent-wide requirement, as it helps improve the system's overall reliability.

Likes 0	
Dislikes 0	
Response	

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2, Group Name IRC Standards Review Committee

Answer	
Document Name	
Comment	

To answer the question directly, the SRC does not believe it is appropriate to require the development of a timetable for implementation of a corrective action plan to address performance issues caused by extreme events. Additionally, an annual review of the implementation status should not be required for extreme events.

More importantly, the SRC does not agree with adding Part 4.2.1 or Part 4.2.2. The substance of Part 4.2.1 is already included in Part 4.5 of R4. The addition of Part 4.2.2, including Parts 4.2.2.1 and 4.2.2.2, is also inappropriate because these provisions could be read to require the TP and PC to prescribe actions to prevent the System from Cascading caused by extreme events – a criterion beyond the basic design and planning criteria. Adding these two parts essentially moves them into the "Steady State & Stability Performance Planning Events" table and a consideration for R2, R3 and R4 for which any unacceptable performance will require actions to mitigate the risks/reliability impacts. This is contrary to the intent of listing the 2a to 2j events under the Extreme Event table.

The addition of Parts 4.2.1 and 4.2.2 also raises a process question. Inadequacy in addressing Cascading caused by Extreme Events was not at all mentioned in Orders 754 or Order 786, nor was it presented in the final SAR for this project. Such addition appears to be a self-directed initiative that goes beyond the scope of the project, which may be regarded as a deviation from established standard development processes. We urge the SDT to revert R4, Part 4.2, to the currently approved version (TPL-001-4).

Note: ISO-NE does not support this comment.

Likes 0	
Dislikes 0	
Response	

2. Do you agree that the requirements of the proposed TPL-001-5 Requirement R4, Parts 4.2.2.1 and 4.2.2.2, including an implementation timetable and annual review of implementation status, should not and do not mandate actual implementation of actions identified as needed to prevent the System from Cascading? For example, do you agree that a capital project is not required to be implemented by Requirement R4, Parts 4.2.2.1 and 4.2.2.2, even if the capital project is the only feasible action available to prevent the System from Cascading when analysis concludes there is Cascading caused by the occurrence of extreme events 2e-2h in the stability column?

Gary Trent - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	No
Document Name	
Comment	
TEP agrees that Requiement R4, Parts 4.2.2.1 and 4.2.2.2 should not mandate actual implementation of actions identified to prevent the System from Cascading. However, the language fail;s to get this point across. Requiring identification of actions to avoid a response along with a timeline to implementthe actions to mitigate the issue implies that these actions must be taken. R4 Part 4.2.2.2 further implies that an entity will be making progress to implement the corrective actions as it reviews the status of the mitigation each year. We agree that mitigation for an extreme event should not be required.	
Likes 0	
Dislikes 0	
Response	

Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
We understand that Parts 4.2.2.1 and 4.2.2.2 require the implementation of corrective action plans to mitigate Cascading caused by extreme events 2e-2h, when analysis concludes a mitigation plan is needed, even if a capital project is the only feasible action available. Corrective action plans should be implemented to prevent Cascading; however, this should be limited to protection system projects.	
Likes 0	
Dislikes 0	
Response	

John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson	
Answer	No
Document Name	
Comment	

A corrective action plan should not be required for an extreme event. Corrective action plans, however, should be required for planning events described in 2e through 2h. While these events are currently included in the extreme events section of Table 1, and since corrective action plans should only be required for planning events, the events described in 2e through 2h should be moved to the planning events section of Table 1 while keeping the criteria to maintain system stability and to avoid cascading or uncontrolled islanding. The Table 1 steady state and stability performance requirements (such as equipment loading, voltage and stability) shall not apply.

ISO-NE does not think that the requirements as written mandate a corrective action plan.

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

The term “Planning Assessment” is defined in the NERC Glossary as a “documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies.” We believe these studies should not be used as a tracking mechanism for Corrective Action Plans, including for those System deficiencies that would require transmission and generation infrastructure upgrades. We propose the removal of references to implementation and timetables and instead focus these requirements on the identification of System deficiencies and associated preventive actions.

Likes 0	
Dislikes 0	

Response

Greg Davis - Greg Davis On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Greg Davis

Answer	No
Document Name	

Comment

GTC agrees that there should not be a mandate of an actual implementation of actions. However, the current language leaves too much room for interpretation and suggests that a CAP is required. We suggest languae similar to Requirement 3.5.

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 Dominion	
Answer	No
Document Name	
Comment	

We understand that Parts 4.2.2.1 and 4.2.2.2 require the implementation of corrective action plans to mitigate Cascading caused by extreme events 2e-2h, when analysis concludes a mitigation plan is needed, even if a capital project is the only feasible action available. Corrective action plans should be implemented to prevent Cascading; however, this should be limited to protection system projects.

The Requirment (Parts 4.2.2.1 and 4.2.2.2), as written, calls for (1) studies to be performed; (2) evaluation of actions (i.e. solution) that would reduce or mitigate (i.e. solve) the identified deficiency; (3) timetable for implementation of the solutions; (4) annual review; and (5) listing of the implementation status. Therefore, the Requirment (Parts 4.2.2.1 and 4.2.2.2), as written, mandates actual implementation of actions identified as needed to prevent the System from Cascading.

Actions to mitigate protection system single point of failure do not usually incur significant cost. Mitigating single points of failure is the direction from FERC order 754. Changes to this Standard was deemed to be the most effective means to accomplish this objective. If corrective actions (capital projects) are not required by this standard, then the FERC objectives may not be achieved which could lead to additional large scale system events or disturbances and additional FERC orders.

Likes 0	
Dislikes 0	
Response	

Payam Farahbakhsh - Hydro One Networks, Inc. - 1	
Answer	No
Document Name	
Comment	

The requirements to have an implementation timetable and annual review, particularly of the "implementation status" suggests that 4.2.2 is mandating a Corrective Action Plan. If this is not the intent of 4.2.2.1 and 4.2.2.2, it must be clarified and explitcity indicated that implementation of a Corrective Action Plan itself (capital project or otherwise) is not required.

Likes 1	Hydro One Networks, Inc., 3, Malozewski Paul
Dislikes 0	
Response	

Ellen Oswald - Midcontinent ISO, Inc. - 2

Answer	No
Document Name	
Comment	

There appears to be very little difference between 4.2.1 and 4.2.2 other than making a list and establishing an implementation timetable that would be meaningless if there is no intent to implement the solution. The current TPL-001-4 wording is sufficient unless there is a desire to require development and implementation of a Corrective Action Plan for certain events and circumstances, in which case, as previously suggested, the contingency should be moved from the extreme event category to a planning contingency category. Otherwise the wording in the current standard regarding extreme events that are found to result in cascading and/or instability should not be modified.

Likes 0	
Dislikes 0	
Response	

Robert Ganley - Long Island Power Authority - 1

Answer	No
Document Name	
Comment	

We believe that the language in proposed TPL-001-5 Requirement R4, Parts 4.2.2.1 and 4.2.2.2 can be interpreted to mean that an actual implementation of actions and/or a capital project(s) is required.

Likes 0	
Dislikes 0	
Response	

Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Document Name	
Comment	

CenterPoint Energy agrees that the requirements of the proposed TPL-001-5 Requirement R4, Parts 4.2.2.1 and 4.2.2.2 should not and do not mandate actual implementation of actions identified in the analysis as being needed to prevent the System from Cascading. However, CenterPoint Energy disagrees with the wording in Requirement R4, Parts 4.2.2.1 and 4.2.2.2 related to implementation. As discussed above, CenterPoint Energy recommends wording for Parts 4.2.2.1 and 4.2.2.2 be similar to Requirement R3, Part 3.5 related to extreme events for the steady state portion of the Planning Assessment.

CenterPoint Energy recommends that Parts 4.2.2.1 and 4.2.2.2 be revised as follows:

4.2.2.1. List System deficiencies, the associated actions needed to prevent the System from Cascading.

4.2.2.2. Be reviewed in subsequent annual Planning Assessments for continued validity.

Likes 0	
Dislikes 0	

Response

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer	No
Document Name	

Comment

Please see comments submitted by Robert Blackne

Likes 0	
Dislikes 0	

Response

Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

We agree that Parts 4.2.2.1 and 4.2.2.2 should not mandate actual implementation but disagree that the language for 4.2.2.1 adequately conveys this. Although the drafting team made its rationale clear for the additional proposed actions for the extreme events 2e-2h, SCE advocates that this language confuses the intent and will create compliance ambiguity in the future. SCE proposes that the drafting team remove sub-requirement R4.2.1 and R4.2.2 (and the underlying R4.2.2.1 & R4.2.2.2) entirely. This change will significantly reduce the confusion for the intention to not obligate entities to actually implement actions identified, and it will keep the compliance obligation clear in the future. Entities should look into actions that may reduce exposure or impact for 2e-2h in the same manner as other extreme events.

Likes 0	
Dislikes 0	

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Randy Hahn,

Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	No
Document Name	
Comment	
FMPA agrees with JEA's comments that part 4.2.2 and all the subparts under it for R4 are not required at all.	
Likes 0	
Dislikes 0	
Response	

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
Requirement 4.2.2 only requires “an evaluation of possible actions designed to prevent the System from Cascading”. ITC believes that if the occurrence of an extreme event (2e-2h) were projected to cause cascading it should mandate actual implementation of actions identified as needed to prevent the System from Cascading.	
Likes 0	
Dislikes 0	
Response	

Lynn Goldstein - PNM Resources - Public Service Company of New Mexico - 1,3	
Answer	No
Document Name	
Comment	
I support PNM's comments.	
Likes 0	
Dislikes 0	
Response	

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	No
Document Name	
Comment	
No. This aspect of the standard does not appear to meet the 'Clear Language' criteria in NERC's Standards Quality Review 'QR' Checklist because the requirement language as written does not assure that entities will be "able to arrive at a consistent interpretation of the required performance.	
Likes 0	
Dislikes 0	
Response	

Quintin Lee - Eversource Energy - 1	
Answer	No
Document Name	
Comment	
Actions to mitigate protection system single point of failure do not usually incur significant cost. Mitigating single points of failure is the direction from FERC order 754. Changes to this Standard was deemed to be the most effective means to accomplish this objective. If corrective actions (capital projects) are not required by this standard, then the FERC objectives may not be achieved which could lead to additional large scale system events or disturbances and additional FERC orders.	
Likes 0	
Dislikes 0	
Response	

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
The words utilized in this question seem to imply that a Corrective Action Plan may not be required. However, the use of the phrases "associated timetable for implementation" and "implementation status" makes the intent misleading. It is unclear how this differs from Requirement 2.7 which states "Corrective Action Plan(s) addressing how the performance requirements will be met." Suggest that Part 4.2.2 and its sub Parts can be struck. If there is a corrective action plan required, as implied by 4.2.2.1, then this event should be listed in Table 1 P5 instead of the Extreme Event Table. Also, in 4.2.1, strike the phrase "excluding extreme events 2e – 2h in the stability column".	
Likes 0	

Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
The “timetable” implies that we are going to fix it but as stated above. WAPA does not believe that there will be a commensurate improvement in system reliability and we have no directive from FERC that actions should be required.	
Likes 0	
Dislikes 0	
Response	
Jeffrey Watkins - Jeffrey Watkins On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins	
Answer	No
Document Name	
Comment	
The requirement calls for listing the deficiencies, the actions needed to prevent the system from cascading, the associated timetable for implementation, and then be reviewed annually with an implementation status. Having an implemention status with a timeline implies that the recommended implementation plan needs to be put into effect. If a capital project is the only feasible action, then it can be interpreted that implementation of the capital project is needed.	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
The language indirectly mandates implementation of construction for system deficiencies resulting from extreme events via a timetable. Otherwise, what is the purpose of developing a timetable if the intent is never to correct the deficiency? We recommend that the SDT remove the timetable	

language and change the language similar to Requirement 4, part 4.2.1 to state "an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted."	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	No
Document Name	
Comment	

No, AZPS does not, based on its review of the language, agree that the Parts 4.2.2, 4.2.2.1, and 4.2.2.2 “should not and do not mandate actual implementation of actions identified as needed to prevent the System from Cascading.” In fact, its comparison of the language to the language of those requirements associated with a mandatory CAP indicates that the language and obligations under Parts 4.2.2, 4.2.2.1, and 4.2.2.2 are actually more robust and stringent. This comparison is provided above in Question 1. For these reasons, AZPS does not agree with the inclusion of Parts 4.2.2, 4.2.2.1, and 4.2.2.2. AZPS submits that these requirements together amount to an actual implementation requirement, and that the language is consistent with a required/ mandatory CAP. Irrespective to whether or not a Transmission Planner believes a capital project is required to be implemented by Parts 4.2.2.1 and 4.2.2.2, the compliance will be determined by the language in the standard. If the language in Parts 4.2.2, 4.2.2.1, and 4.2.2.2 are essentially the same as that for a CAP, the requirement is essentially equivalent to CAP.

If Parts 4.2.2, 4.2.2.1, and 4.2.2.2 are not removed as requested above, to clarify the intent stated in this question, AZPS recommends the following revisions to the proposed language for Parts 4.2.2, 4.2.2.1, and 4.2.2.2:

4.2.2 If the analysis concludes there is Cascading caused by the occurrence of extreme events 2e -2h

4.2.2.1 Document the list of System deficiencies and actions that could be taken to prevent the System from Cascading.

4.2.2.2 Review the list of System Deficiencies and potential actions to address such System deficiencies in subsequent annual Planning Assessments for continued validity

Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No
Document Name	
Comment	

The way it reads seems to imply an implementation of actions is required and that action could result in a capital project. If the only feasible means to prevent a cascading event is a capital project then this seems to be a meaningless exercise if there is no requirement to implement it.

Likes 0	
Dislikes 0	

Response
Thomas Foltz - AEP - 5

Answer	No
Document Name	

Comment
The language of these proposed subrequirements does not suggest that actual implementation is optional. The components of a Corrective Action Plan as defined in the NERC Glossary are clearly required by the proposed 4.2.2.1. 4.2.2.2 contains an expectation that the actions needed to prevent the cascading would be implemented at some point. Again, we question the point of devising preventive actions and an associated timetable, and performing an annual review of implementation status for mitigating actions that are supposedly never to be "required." In addition, 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. If mitigation is truly not required, then the language of R4.5 in TPL-001-4 is all that should be necessary. Once again, as stated in our response to Question 1, AEP believes that pursuing Corrective Action Plans as part of R4, Part 4.6 goes beyond the scope of the current SAR. Please note that AEP has chosen to vote Negative on TPL-001-5, in large part due to our objections as provided in our response to Questions #1 and #2.

Likes 0	
Dislikes 0	

Response
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1

Answer	No
Document Name	

Comment
The Requirment (Parts 4.2.2.1 and 4.2.2.2), as written, calls for (1) studies to be performed; (2) evaluation of actions (i.e. solution) that would reduce or mitigate (i.e. solve) the identified deficiency; (3) timetable for implementation of the solutions; (4) annual review; and (5) listing of the implementation

status. Therefore, the Requirment (Parts 4.2.2.1 and 4.2.2.2), as written, mandates actual implementation of actions identified as needed to prevent the System from Cascading.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA believes that requiring an implementation plan and timetable is similar to a corrective action plan and is being mandated. Until the studies are done, it can not be determined if any capital projects were included. In general, the utility will determine whether or not to address an issue based on risks and consequences of the event.	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts	
Answer	No
Document Name	
Comment	
Requirement parts 4.2.2.1 and 4.2.2.2 require Responsible Entities to create associated actions and a timetable for implementation. Compliance enforcement staff could interpret the requirement such that a documented action is required to be implemented.	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

SRP agrees TPL-001-5 should not mandate actual implementation of a Corrective Action Plan. However, the current language of 4.2.2.2. leaves too much of a gray area that is open for interpretation as mandating actual implementation. SRP recommends removing 4.2.2.2. altogether. The impacts of extreme events 2e-2h in the stability column, and the actions required to prevent the System from cascading are addressed by 4.2.2. and the first part of 4.2.2.1. in every annual Planning Assessment. Requiring a review "for continued validity" is redundant, and requiring a timetable for implementation or a review of implementation status is unnecessary for a NERC Reliability Standard.	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
MH believes the language in 4.2.2.1 and 4.2.2.2, as written, mandates construction to prevent Cascading for extreme events. The wording of this question is confusing "... should not and do not mandate ...". If the first sentence is intended to breakup as follows: Do you agree that …….. should not mandate ……? Answer - Yes Do you agree that……… do not mandate …………..? Answer - No	
Likes 1	Manitoba Hydro , 5, Xiao Yuguang
Dislikes 0	
Response	
John Seelke - LS Power Transmission, LLC - 1	
Answer	No
Document Name	
Comment	
The way it reads seems to imply an implementation of actions is required and that action could result in a capital project. If the only feasible means to prevent a cascading event is a capital project then this seems to be a meaningless exercise if there is no requirement to implement it. Permitting the implementation of capital projects to be optional when it is the only feasible solution subjects the utility to the possibility that the state commissions might view the capital project (expenditure) as not necessary for reliability given that the justification is based on an extreme event(s).	
Likes 0	
Dislikes 0	
Response	

Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	No
Document Name	
Comment	
Oftentimes the capital project may be a relay upgradeproject which is relatively low cost compared to the benefits.	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1,5, Group Name LCRA Compliance	
Answer	No
Document Name	
Comment	
Oftentimes the capital project may be a relay upgrade project which is relatively low cost compared to the benefits.	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2, Group Name IRC Standards Review Committee	
Answer	No
Document Name	
Comment	
In addition to our comments under Q1, we believe that analyzing system performance when subject to "Extreme Events" is meant to provide a sense of where instability and/or Cascading could occur for the PC and/or TP to assess what actions could be developed to mitigate or reduce the potential impact. Such actions generally involve positioning the BES, adjusting outage plans, implementing operations strategies, developing a safe posture and preparing for resiliency plans, but not any capital investment projects. Note that this does not preclude the responsible entity from implementing any of these actions in its sole discretion, but it should not be mandated. Capital projects to address operational circumstances should not be mandated in a TPL standard. Further, requiring capital projects would exceed the scope of FERC Order 754 and 786 as well as the SAR. **Note: ISO-NE does not support this 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	
ALAN ADAMSON - New York State Reliability Council - 10	
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	Yes
Document Name	
Comment	
The SPP Standards Review Group recommends that the drafting team adds language to section 4.2.2.2 to clarify during the review process pertaining to the Planning Assessments for continued validity and implementation status that an adjustable time frame would always be taken into consideration.	
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 agrees that no corrective action plan should be required for extreme events 2e-h in accordance with the actions the FERC and FRCC have agreed to in XXXXXX (need reference from Fabio). Therefore there is no need for any wording regarding implementation.	
Likes 0	
Dislikes 0	
Response	
Kevin Giles - Westar Energy - 1	
Answer	Yes
Document Name	
Comment	
Westar agrees with the SPP Standards Review Group to recommend that the drafting team adds language to section 4.2.2.2 to clarify during the review process pertaining to the Planning Assessments for continued validity and implementation status that an adjustable time frame would always be taken into consideration.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
We believe implementation of actions should not be mandated. In addition, because the actual implementation is not mandated, the timetable for implementation should not be required either.	
Likes 0	
Dislikes 0	
Response	

Joe McClung - JEA - 1,3,5 - FRCC, Group Name JEA Voters	
Answer	Yes
Document Name	
Comment	
Per our (JEA's) comment for Question #1, part 4.2.2 and all the subparts under it for Requirement R4 are not required at all. Hence this question #2 becomes moot for an extreme event. However for the Planning Event P5 with the added clarification with footnote 13, new situations can be unearthed in the new studies which may require an implementation timetable and an annual review of the implementation status for a capital project as part of the Corrective Action Plan	
Likes 1	JEA, 5, Babik John
Dislikes 0	
Response	
Long Duong - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
SNPD does not have additional comments.	
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	
Yes. SCL agrees with simulation of extreme events to develop awareness of the constraints, if any, of the BES. Implementing actions for extreme events is not necessary, because the corrective action plan can be costly and not produce much benefit due to the low frequency of extreme types of events happening.	
Likes 0	
Dislikes 0	

Response

Janis Weddle - Public Utility District No. 1 of Chelan County - 6	
Answer	Yes
Document Name	
Comment	
CHPD agrees that the requirement should not mandate implementation of actions identified as needed to prevent the System from Cascading. CHPD agrees that a capital project should not be required to prevent Cascading as these Extreme Events have a low likelihood of occurring and are costly to mitigate.	
Likes 0	
Dislikes 0	
Response	

Joyce Gundry - Public Utility District No. 1 of Chelan County - 3	
Answer	Yes
Document Name	
Comment	
CHPD agrees that the requirement should not mandate implementation of actions identified as needed to prevent the System from Cascading. CHPD agrees that a capital project should not be required to prevent Cascading as these Extreme Events have a low likelihood of occurring and are costly to mitigate.	
Likes 0	
Dislikes 0	
Response	

David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
If small system upgrades can be implemented to keep the system from cascading, we believe that these upgrades should be pursued in a timely manner. But as mentioned above, why does part 4.2.2 require fixes for failure of non-redundant relaying components? Why isn't this requirement part of the PRC standards, but is proposed for standard TPL-001?	
Likes 0	

Dislikes 0	
Response	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	Yes
Document Name	
Comment	
Please refer to comment for Question 1.	
Likes 0	
Dislikes 0	
Response	
Haley Sousa - Public Utility District No. 1 of Chelan County - 5, Group Name Chelan PUD	
Answer	Yes
Document Name	
Comment	
CHPD agrees that the requirement should not mandate implementation of actions identified as needed to prevent the System from Cascading. CHPD agrees that a capital project should not be required to prevent Cascading as these Extreme Events have a low likelihood of occurring and are costly to mitigate.	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Anderson - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Fred Frederick - Southern Indiana Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE agrees that the current language does not mandate actual implementation. However, Texas RE would support requirements mandating implementation of the actions determined by the PC and TP to reduce the likelihood of Cascading consistent with regional planning processes. Additionally, Texas RE would support the development of a Corrective Action Plan that included a capitol project designed to mitigate Cascading if that were the only option. Generally capital projects endure scrutiny by the planning processes in the Texas RE region.	

Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5	
Answer	
Document Name	
Comment	
Please see comments of Joe O'Brien NIPSCO.	
Likes 0	
Dislikes 0	
Response	

3. Do you agree with the omission, as proposed in TPL-001-5 Requirement R4, Part 4.2, of a requirement similar to that of Requirement R2, Part 2.7, which states that the planned System shall continue to meet the performance requirements in Table 1 in subsequent Planning Assessments?

Mike Smith - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
If the PC decides to implement a Corrective Action plan to address an extreme event, they should be allowed to modify it, but they shouldn't be held to meeting performance requirements. Maybe the change is lower in cost and limits the extent of Cascading.	
Likes 1	Manitoba Hydro , 5, Xiao Yuguang
Dislikes 0	
Response	

Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
Answer	No
Document Name	
Comment	
The proposed language of Part 4.2.1 and 4.2.2 in TPL-001-5 is an addition, not an omission. We disagree with adding the 4.2.2.1 requirement to list a timetable for implementation of actions to reduce the likelihood or mitigate the consequences of any extreme contingence events, including extreme events 2e-2h and the 4.2.2.2 requirement to continue to review the validity and implementation status of the possible actions.	
Likes 0	
Dislikes 0	
Response	

sean erickson - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
We agree with the omission, however, we disagree with adding the 4.2.2.1 requirement to list a timetable for implementation of actions to reduce the likelihood or mitigate the consequences of any extreme contingence events, including extreme events 2e-2h and the 4.2.2.2 requirement to continue to review the validity and implementation status of the possible actions.	

Likes 0	
Dislikes 0	

Response

Quintin Lee - Eversource Energy - 1

Answer	No
Document Name	

Comment

If a system risk or vulnerability has been identified as a result of conducting a mandatory reliability assessment, Corrective Action Plan(s) must be developed which maintains system performance. Customers and regulators will not accept that a system deficiency was identified but not mitigated by a Transmission Planner when such an event occurs. If maintaining system performance following an event is not required, then performing an assessment of that event should not be required.

Likes 0	
Dislikes 0	

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	No
Document Name	

Comment

The proposed language of Part 4.2.1 and 4.2.2 in TPL-001-5 is an addition, not an omission. We disagree with adding the 4.2.2.1 requirement to list a timetable for implementation of actions to reduce the likelihood or mitigate the consequences of any extreme contingence events, including extreme events 2e-2h and the 4.2.2.2 requirement to continue to review the validity and implementation status of the possible actions.

Likes 0	
Dislikes 0	

Response

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer	No
Document Name	

Comment

Please see comments submitted by Robert Blackne

Likes 0	
Dislikes 0	
Response	
Ellen Oswald - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	

The planned system should always meet the performance requirements in Table 1 in any Planning Assessment that is performed. To the extent a Corrective Action Plan is developed for issues identified in one Planning Assessment and the issues go away in subsequent Planning Assessments due to changes in load forecasts or other drives of the original issue, elimination or modification of the Corrective Action Plan in the subsequent Planning Assessment should certainly be allowed, but the language above that states "the planned System shall continue to meet the performance requirements in Table 1 in subsequent Planning Assessments" seems unnecessary since the Table 1 requirements apply to all Planning Assessments.

Likes 0	
Dislikes 0	
Response	
Payam Farahbakhsh - Hydro One Networks, Inc. - 1	
Answer	No
Document Name	
Comment	

We support mandating the implementation of Corrective Action Plans if they are limited to protection system modifications.

Likes 1	Hydro One Networks, Inc., 3, Malozewski Paul
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion	
Answer	No
Document Name	
Comment	

As mentioned in our response to Q2, our interpretation of Part 4.2.2 is that it requires the implementation of corrective action plans –including capital projects– when analysis concludes there is Cascading. We support the implementation of corrective action plans.

If the drafting team considers that this is not the intent of the revision, and the implementation of capital projects IS NOT required, we propose that Part 4.2.2 be revised to make this clear.

If a system risk or vulnerability has been identified as a result of conducting a mandatory reliability assessment, Corrective Action Plan(s) must be developed which maintains system performance. Customers and regulators will not accept that a system deficiency was identified but not mitigated by a Transmission Planner when such an event occurs. If maintaining system performance following an event is not required, then performing an assessment of that event should not be required.

Likes 0	
Dislikes 0	

Response

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6

Answer	No
Document Name	

Comment

See MidAmerican Energy's comments. There should not be a requirement to mitigate extreme events.

Likes 0	
Dislikes 0	

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer	No
Document Name	

Comment

As mentioned in our response to Q2, our interpretation of Part 4.2.2 is that it requires the implementation of corrective action plans –including capital projects– when analysis concludes there is Cascading. We support the implementation of corrective action plans.

If the drafting team considers that this is not the intent of the revision, and the implementation of capital projects IS NOT required, we propose that Part 4.2.2 be revised to make this clear.

Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	No
Document Name	
Comment	
The proposed language of Part 4.2.1 and 4.2.2 in TPL-001-5 is an addition, not an omission. We disagree with adding the 4.2.2.1 requirement to list a timetable for implementation of actions to reduce the likelihood or mitigate the consequences of any extreme contingence events, including extreme events 2e-2h and the 4.2.2.2 requirement to continue to review the validity and implementation status of the possible actions.	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1,5, Group Name LCRA Compliance	
Answer	No
Document Name	
Comment	
It is appropriate to meet performance requirements in subsequent planning assessments	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	No
Document Name	
Comment	
It is appropriate to meet performance requirements in subsequent planning assessments.	
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	
Analysis of extreme events for awareness of BES constraints is sufficient, so meeting performance requirements for subsequent planning asssessment is not necessary.	
Likes 0	
Dislikes 0	
Response	

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
For extreme events, the planned System should not be required to meet the performance requirements of Table 1.	
Likes 0	
Dislikes 0	
Response	

Long Duong - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
SNPD does not have additional comments.	
Likes 0	
Dislikes 0	
Response	

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

BPA believes that the omission in 4.2 is necessary as there are not performance requirements in the Table for Extreme Events.

BPA believes the focus should be all about reducing the likelihood, not preventing it. We do not agree with separating out extreme events in 2e-2h, everything should be included in 4.2.1

BPA believes that 4.2.1 should be modified to remove "excluding extreme events 2e-2h in the stability column".

Likes 0	
Dislikes 0	
Response	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	Yes
Document Name	
Comment	

Agree.

Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	

AEP agrees with the omission but we are not persuaded that this omission would excuse a TP or PC from implementation of what may very well be construed as Corrective Action Plans under the proposed R4.2.2.

Likes 0	

Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
While we agree that there should be an omission, the use of the phrases “associated timetable for implementation” and “implementation status” in R4.2 gives the perception that capital projects would be required. It is unclear how this differs from Requirement 2.7 which states “Corrective Action Plan(s) addressing how the performance requirements will be met.” Suggest that Part 4.2.2 and its sub Parts can be struck. If there is a corrective action plan required, as implied by 4.2.2.1, then this event should be listed in Table 1 P5 instead of the Extreme Event Table. Also, in 4.2.1, strike the phrase “excluding extreme events 2e – 2h in the stability column”.	
Likes 0	
Dislikes 0	
Response	
Robert Ganley - Long Island Power Authority - 1	
Answer	Yes
Document Name	
Comment	
We concur with the omission. We do not believe that actions to mitigate Cascading are required for meeting the performance requirements in Table 1 when subject to Extreme Events. The continued omission of such a requirement in R4 is justified.	
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	

Yes. We agree that a requirement to ensure that Cascading does not occur in subsequent Planning Assessment given extreme events 2e-2h in the stability column should be omitted. Further, to include a requirement such as this would be identical to a Corrective Action Plan.	
Likes 0	
Dislikes 0	
Response	
John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson	
Answer	Yes
Document Name	
Comment	
ISO-NE agrees that a corrective action plan should not be required for an extreme event. The 2e through 2h events referenced in Requirement R4, Part 4.2.2, however, should be planning events and, accordingly, corrective action plans should be required for them.	
Likes 0	
Dislikes 0	
Response	
Gary Trent - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	Yes
Document Name	
Comment	
TEP agrees that extreme events do not need the same level of requirements as Planning Events.	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2, Group Name IRC Standards Review Committee	
Answer	Yes
Document Name	
Comment	

Consistent with our comments under Q1 and Q2, we do not believe that actions to mitigate Cascading are required for meeting the performance requirements in Table 1 when subject to Extreme Events. The continued omission of such a requirement in R4 is justified.	
Likes 0	
Dislikes 0	
Response	
Haley Sousa - Public Utility District No. 1 of Chelan County - 5, Group Name Chelan PUD	
Answer	Yes
Document Name	
Comment	
To confirm, in summary R4.2 for extreme events has been re-drafted in R4.2.1. to exclude the new expanded definition of protection system failure events from the evaluation covered in R4.2.2. which specifically applies additional requirement to the new protection system failure events. Based on this interpretation, this is an acceptable omission for those non-protection system failure events. However, CHPD feels Corrective Action Plans should not be required to mitigate all Extreme Events (including protection system failure) because it would be costly and have little benefit as Extreme Events have a low likelihood of happening. Thus, these Extreme Events are studied for system awareness and determining the constraints of the system.	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	Yes
Document Name	
Comment	
The omission as proposed in Requirement R4, Part 4.2 seems to allow a little more flexibility in our interpretation in how we meet the performance requirements in Table 1 for our Planning Assessment.	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	

Comment	
We believe that requirement 2.7 would cover system performance for the R4 requirements.	
Likes 0	
Dislikes 0	
Response	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3	
Answer	Yes
Document Name	
Comment	
To confirm, in summary R4.2 for extreme events has been re-drafted in R4.2.1. to exclude the new expanded definition of protection system failure events from the evaluation covered in R4.2.2. which specifically applies additional requirement to the new protection system failure events. Based on this interpretation, this is an acceptable omission for those non-protection system failure events. However, CHPD feels Corrective Action Plans should not be required to mitigate all Extreme Events (including protection system failure) because it would be costly and have little benefit as Extreme Events have a low likelihood of happening. Thus, these Extreme Events are studied for system awareness and determining the constraints of the system.	
Likes 0	
Dislikes 0	
Response	
Janis Weddle - Public Utility District No. 1 of Chelan County - 6	
Answer	Yes
Document Name	
Comment	
To confirm, in summary R4.2 for extreme events has been re-drafted in R4.2.1. to exclude the new expanded definition of protection system failure events from the evaluation covered in R4.2.2. which specifically applies additional requirement to the new protection system failure events. Based on this interpretation, this is an acceptable omission for those non-protection system failure events. However, CHPD feels Corrective Action Plans should not be required to mitigate all Extreme Events (including protection system failure) because it would be costly and have little benefit as Extreme Events have a low likelihood of happening. Thus, these Extreme Events are studied for system awareness and determining the constraints of the system.	
Likes 0	
Dislikes 0	
Response	

John Seelke - LS Power Transmission, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe McClung - JEA - 1,3,5 - FRCC, Group Name JEA Voters	
Answer	Yes
Document Name	
Comment	
Likes 1	JEA, 5, Babik John
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	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Anderson - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey Watkins - Jeffrey Watkins On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
ALAN ADAMSON - New York State Reliability Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lynn Goldstein - PNM Resources - Public Service Company of New Mexico - 1,3	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Giles - Westar Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
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	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
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	
Greg Davis - Greg Davis On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Greg Davis	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 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	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
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	
Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Fred Frederick - Southern Indiana Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5	
Answer	
Document Name	
Comment	
Please see comments of Joe O'Brien NIPSCO.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Part 2.7 is referring to the planning events Table 1 which has performance requirements for maintaining a normal system. Part 4.2 is referring to the extreme events, which does not have performance requirements in Table 1. A similar requirement is not needed because Part 4.2 says to perform studies to assess the impact of extreme events and conduct an evaluation of possible actions that could reduce the likelihood, mitigate, or prevent Cascading that occurs due to an extreme event in the list.	
Likes 0	
Dislikes 0	
Response	

4. Do you agree with including Table 1 Footnote 13 a., “[a] single protective relay which responds to electrical quantities, without an alternative that provides comparable Normal Clearing times, *e.g*., sudden pressure relaying”, and its limitation to only the specific single protective relay and not to other elements of the associated Protection System?

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 recommends that the drafting team provide more clarity in reference to the example in Footnote 13 (a) to refer to alternate performance to achieve electrical clearance rather than the relay to electrical quantities in which it may cause confusing on how it’s interpreted.

Likes 0	
Dislikes 0	

Response

John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson

Answer	No
Document Name	

Comment

ISO-NE suggests revising footnote 13-1 to read as follows:

1. A single protective relay that is relied on for Normal Clearing times, without an alternative that provides comparable Normal Clearing times.

A protection system may rely on a single protective relay that does not respond to electrical quantities such as a sudden pressure relay. Therefore, having the footnote refer to only relays that respond to electrical quantities may allow the failure of other critical relays to be ignored.

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

We believe the SDT should specify the actions taken by a single protective relay instead of identifying individual Protection System components for this standard. The reference to “an alternative that provides comparable Normal Clearing times” is confusing when associated with sudden pressure relays and included as a condition for non-redundant components of a Protection System.

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
We agree with the concept as layed out in the question, which limits the scope of what needs to be studied. However, the bullet points do not match up with the documents reviewed (13.1 vs 13.a).

Likes 0	
Dislikes 0	

Response
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6

Answer	No
Document Name	

Comment
Remove “e.g. sudden pressure relaying” text

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 Dominion

Answer	No
Document Name	

Comment

Please clarify what constitutes an "alternative" relay. Is an "alternative" relay only referring to a relay that does not respond to electrical quantities? Further, what if alternative relay does not provide the same clearing time as primary relay (e.g., the alternate relay is an impedance relay with longer Zone 2 timer, or alternative relay is overcurrent relay, while primary relay is impedance relay). Is the alternative relay then considered as 'redundant', and therefore footnote 13 does not apply? We do not believe it is fully clear of what constitutes "comparable" in the context of comparable Normal Clearing times in Table 1 Footnote 13 Part 1. We further do not believe that it is fully clear what is required for a relay to be "monitored." Is it required that alarms are centrally monitored (i.e., reported within 24 hours of detecting an abnormal condition to a location where corrective action can be initiated)? Cf. 'Single Points of Failure TPL-001 Technical Rationale' document.

Suggest adding parenthesis to clarify that sudden pressure relays are excluded.

"[a] single protective relay which responds to electrical quantities (without an alternative that provides comparable Normal Clearing times, e.g., sudden pressure relaying)". As it is written currently, "sudden pressure relaying" would seem to respond to electrical quantities.

Likes 1	PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey
Dislikes 0	

Response

Robert Ganley - Long Island Power Authority - 1

Answer	No
Document Name	

Comment

We agree with the attempt to clarify Table 1 Footnote 13 a. However, it is not clearly understood what is meant by the second part of the proposed statement "without an alternative that provides comparable Normal Clearing times, e.g., sudden pressure relaying". For example, does this mean that if an alternative that provides comparable Normal Clearing times exists, then the single protective relay that responds to electrical quantities is not considered "non-redundant" (and therefore would not be considered a non-redundant component of a Protection System)?? Recommendation is to re-word the sentence to make it absolutely clear.

Likes 0	
Dislikes 0	

Response

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer	No
Document Name	

Comment

Please see comments submitted by Robert Blackne

Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	

The item label in TPL-001-5 is Footnote 13 1, not Footnote 13 a. We agree with having a single protective relay item in Footnote 13 and acknowledge that contemporary protective relay units normally perform multiple fault protection functions. However, we suggest removing the “, e.g. sudden pressure relaying” text for two reasons. First, sudden pressure relaying does not provide full redundancy of a transformer protection relay unit’s functionality, but the present wording gives the impression that sudden pressure relaying will always provide full transformer protection relay redundancy. Second, the sudden pressure relay wording is somewhat confusing and can appear to identify sudden pressure relays as a type of protective relays to be evaluated.

Note: Equipment protection should not be confused with the TPL-001-5 reliability objective of providing adequate transmission capability to meet TPL-001-5 criteria avoiding instability, uncontrolled separation, and cascading. Sudden Pressure relays may be used as an additional protection to avoid equipment damage by removing a transformer quickly under specific conditions versus normal transformer differential protection.

Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	No
Document Name	
Comment	

Suggest adding parenthesis to clarify that sudden pressure relays are excluded.

“[a] single protective relay which responds to electrical quantities (without an alternative that provides comparable Normal Clearing times, e.g., sudden pressure relaying)”. As it is written currently, “sudden pressure relaying” would seem to respond to electrical quantities.

Likes 0	
Dislikes 0	
Response	
Jeffrey Watkins - Jeffrey Watkins On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins	
Answer	No

Document Name	
Comment	

NVE agrees with the intent of Footnote 13a, but would like to see clarification with the wording especially on terms (i.e. “comparable”). Perhaps, a defined term should be created similar to the WECC regional definition of ‘Functionally Equivalent Protection System’. Footnote 13a, could then be re-written to “[a] single protective relay without a Functionally Equivalent Protection System.” This would then cover multiple cases including the example provided in the Technical Rationale between the differential relay and sudden pressure relay.

Likes 0	
Dislikes 0	
Response	

Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6

Answer	No
Document Name	
Comment	

The item label in TPL-001-5 is Footnote 13 1, not Footnote 13 a. We agree with having a single protective relay item in Footnote 13 and acknowledge that contemporary protective relay units normally perform multiple fault protection functions. However, we suggest removing the “, e.g. sudden pressure relaying” text for two reasons. First, sudden pressure relaying does not provide full redundancy of a transformer protection relay unit’s functionality, but the present wording gives the impression that sudden pressure relaying will always provide full transformer protection relay redundancy. Second, the sudden pressure relay wording is somewhat confusing and can appear to identify sudden pressure relays as a type of protective relays to be evaluated.

Note: Equipment protection should not be confused with the TPL-001-5 reliability objective of providing adequate transmission capability to meet TPL-001-5 criteria avoiding instability, uncontrolled separation, and cascading. Sudden Pressure relays may be used as an additional protection to avoid equipment damage by removing a transformer quickly under specific conditions. The difference between Sudden Pressure relay trips and regular protection system trips may avoid equipment damage, but may not have any impact on instability, uncontrolled separation, or cascading.

Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5

Answer	No
Document Name	
Comment	

AEP seeks clarity on the intent of the use of the term “comparable” relative to the NERC Glossary Term Normal Clearing Time. Would a Protection System designed with a communication-aided primary relay and a step-distance backup relay for the same BES line be considered non-redundant per footnote 13a?

Likes 0	
Dislikes 0	
Response	

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	No
Document Name	

Comment

Dominion Energy agrees that other relay types such as sudden pressure relays can respond just as quickly to fault conditions and should be counted as a redundant component. Dominion Energy does not understand the rationale for limiting this to just the single protective relay and not other protective elements. For example, would it not be possible that the sudden pressure relay uses a separate trip path that would create the redundancy necessary? Should that not count towards the redundancy?

Likes 3	Luiggi Beretta, N/A, Beretta Luiggi; PSEG - PSEG Fossil LLC, 5, Kucey Tim; PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	
Response	

John Seelke - LS Power Transmission, LLC - 1

Answer	No
Document Name	

Comment

A sudden pressure relay doesn’t respond to electrical quantities. It is not even a component of a “Protection System,” which is the premise of the lead sentence of Footnote 13: “For purposes of this standard, non-redundant components of a *Protection System* to consider are as follows:” The drafting team may be confused because sudden pressure relays are included in PRC-005-6 – Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance. But as its title indicates, “Automatic Reclosing” and “Sudden Pressure Relays” are distinct from “Protection System.”

Likes 0	
Dislikes 0	
Response	

Lauren Price - American Transmission Company, LLC - 1 - MRO,RF

Answer	No
Document Name	
Comment	
The item label in TPL-001-5 is Footnote 13 1, not Footnote 13 a. We agree with having a single protective relay item in Footnote 13 and acknowledge that contemporary protective relay units normally perform multiple fault protection functions. However, we suggest removing the ", e.g. sudden pressure relaying" text for two reasons. First, sudden pressure relaying does not provide full redundancy of a transformer protection relay unit's functionality, but the present wording gives the impression that sudden pressure relaying will always provide full transformer protection relay redundancy. Second, the sudden pressure relay wording is somewhat confusing and can appear to identify sudden pressure relays as a type of protective relays to be evaluated.	
Likes 0	
Dislikes 0	
Response	
Ellen Oswald - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Footnote 13 should indicate that single protective relay applies to a relay unit and not a relay element. Multiple relay elements within a single relay unit (e.g., multiple elements in a common digital relay, etc.) are not redundant since a common failure (e.g., power supply) could impact all relay elements within the relay unit.	
Likes 0	
Dislikes 0	
Response	
Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
CenterPoint Energy agrees with including Table 1 Footnote 13 a., "[a] single protective relay which responds to electrical quantities, without an alternative that provides comparable Normal Clearing times, *e.g.*, sudden pressure relaying." Presently, only Sudden Pressure Relaying meets this wording based on a NERC System Protection and Control Subcommittee report (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) and the approved NERC Standard PRC-005 Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance. The proposed wording by the SDT for Table 1	

Footnote 13 allows other types of relays that do not respond to electrical quantities to be added in the future, when approved, eliminating the need to revise this requirement in TPL-001-5.

Likes 0	
Dislikes 0	

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer	Yes
Document Name	

Comment

This question is not worded very clearly. We believe the question is asking whether we agree that the language added should only apply to 13a and not to 13 b, c, or d (which we agree with). However, as written, it is very confusing since the quotes include the term "single protective relay" and then we are asked if we agree to "its limitation to only the specific single protective relay".

Likes 0	
Dislikes 0	

Response

sean erickson - Western Area Power Administration - 1

Answer	Yes
Document Name	

Comment

WAPA agrees with having a single protective relay item in Footnote 13 and acknowledges that contemporary protective relay units normally perform multiple fault protection functions. However, we suggest removing the “, e.g. sudden pressure relaying” text for two reasons. First, sudden pressure relaying does not provide full redundancy of a transformer protection relay unit’s functionality, but the present wording gives the impression that sudden pressure relaying will always provide full transformer protection relay redundancy. Second, the sudden pressure relay wording is somewhat confusing and can appear to identify sudden pressure relays as a type of protective relays to be evaluated.

Note: Equipment protection should not be confused with the TPL-001-5 reliability objective of providing adequate transmission capability to meet TPL-001-5 criteria avoiding instability, uncontrolled separation, and cascading. Sudden Pressure relays may be used as an additional protection to avoid equipment damage by removing a transformer quickly under specific conditions. The difference between Sudden Pressure relay trips and regular protection system trips may avoid equipment damage, but may not have any impact on instability, uncontrolled separation, or cascading.

Likes 0	

Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
However, the following wording would be clearer: "[a] single protective relay which responds to electrical quantities, without an alternative that responds to non-electrical quantities and provides comparable Normal Clearing times, *e.g.*, sudden pressure relaying"	
Likes 0	
Dislikes 0	
Response	
James Anderson - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
However, the following wording would be clearer: "[a] single protective relay which responds to electrical quantities, without an alternative that *responds to non-electrical quantities and* provides comparable Normal Clearing times, *e.g.*, sudden pressure relaying",	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
The Technical Rationale provides an example of fault in a transformer and the use of a sudden pressure relay. However, this is of no practical value since the Transmission Planner still has to account for the fault outside of the transformer tank and the sudden pressure relay will not protect against that. There is no benefit of adding this language related to an alternative device.	
Likes 0	

Dislikes 0	
Response	
Jeanne Kurzynowski - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
However, the following wording would be clearer: “[a] single protective relay which responds to electrical quantities, without an alternative that responds to non-electrical quantities and provides comparable Normal Clearing times, *e.g.*, sudden pressure relaying”	
Likes 0	
Dislikes 0	
Response	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	Yes
Document Name	
Comment	
Agree.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA agrees. BPA believes that there is inconsistency between the redlined and clean versions of the standard. The Redlined version identifies Footnotes correctly as 13 a,b,c,d; Clean version shows 13 1,2,3,4. Please correct.	
Likes 0	

Dislikes 0	
Response	
Long Duong - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
SNPD does not have additional comments.	
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	
No Comments	
Likes 0	
Dislikes 0	
Response	
Janis Weddle - Public Utility District No. 1 of Chelan County - 6	
Answer	Yes
Document Name	
Comment	
If the scope was broadened to include other elements associated with the Protection System (like PTs, CTs, Comm gear, etc.) the contingency list would be overbearing and would not add any benefit to the analysis. Failure of these other elements would produce redundant results to protection system failure events which are already evaluated. CHPD finds this clarification helpful in explaining the expectation of the applicable requirement, but would also note that this definition of non-redundant components is different than the other NERC definitions of non-redundant components addressed in the 2009 NERC document “Protection System	

Reliability – Redundancy of Protection," as well as some of the redundancy methods and requirements described in PRC-012-2 (for RAS systems), which is subject to future enforcement. These multiple NERC definitions of acceptable types of redundancy will likely cause confusion in industry.	
Likes 0	
Dislikes 0	
Response	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3	
Answer	Yes
Document Name	
Comment	
If the scope was broadened to include other elements associated with the Protection System (like PTs, CTs, Comm gear, etc.) the contingency list would be overbearing and would not add any benefit to the analysis. Failure of these other elements would produce redundant results to protection system failure events which are already evaluated. CHPD finds this clarification helpful in explaining the expectation of the applicable requirement, but would also note that this definition of non-redundant components is different than the other NERC definitions of non-redundant components addressed in the 2009 NERC document "Protection System Reliability – Redundancy of Protection," as well as some of the redundancy methods and requirements described in PRC-012-2 (for RAS systems), which is subject to future enforcement. These multiple NERC definitions of acceptable types of redundancy will likely cause confusion in industry.	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	Yes
Document Name	
Comment	
The specific explanation for a single protective relay (alternative that provides comparable Normal Clearing times, e.g. sudden pressure relaying.) seems to provide more clarity on how we can include these relay protection failure scenarios within our Stability Analysis contingencies.	
Likes 0	
Dislikes 0	
Response	

Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
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	

Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Greg Davis - Greg Davis On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Greg Davis

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Payam Farahbakhsh - Hydro One Networks, Inc. - 1

Answer	Yes
Document Name	

Comment

Likes 1	Hydro One Networks, Inc., 3, Malozewski Paul
Dislikes 0	

Response

Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC

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	

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kevin Giles - Westar Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 4	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Lynn Goldstein - PNM Resources - Public Service Company of New Mexico - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	

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	
Joe McClung - JEA - 1,3,5 - FRCC, Group Name JEA Voters	
Answer	Yes
Document Name	
Comment	
Likes 1	JEA, 5, Babik John
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1, 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	
Mike Smith - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 1	Manitoba Hydro , 5, Xiao Yuguang
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1,5, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Fred Frederick - Southern Indiana Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2, Group Name IRC Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE agrees with including protective relays in Footnote 13. As stated in its comments for the Standard Authorization Request (SAR), Texas RE noticed the proposed language for Footnote 13 does not match the NERC Glossary term of Protection System. The NERC Glossary definition states: “Protective relays which respond to electrical quantities” while Footnote 13 states “a single protective relay which responds to electrical quantities, without an alternative that provides comparable Normal Clearing times, e.g. sudden pressure relaying.” Texas RE recommends Footnote 13 align with the NERC Glossary to avoid confusion. Texas RE noticed Footnote 13 is listed in number format, not letters as questions 4, 5, and 6 indicate on this form.	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5	
Answer	
Document Name	
Comment	
Please see comments of Joe O'Brien NIPSCO.	

Likes 0	
Dislikes 0	

Response

Haley Sousa - Public Utility District No. 1 of Chelan County - 5, Group Name Chelan PUD

Answer	
Document Name	

Comment

If the scope was broadened to include other elements associated with the Protection System (like PTs, CTs, Comm gear, etc.) the contingency list would be overbearing and would not add any benefit to the analysis. Failure of these other elements would produce redundant results to protection system failure events which are already evaluated.

CHPD finds this clarification helpful in explaining the expectation of the applicable requirement, but would also note that this definition of non-redundant components is different than the other NERC definitions of non-redundant components addressed in the 2009 NERC document “Protection System Reliability – Redundancy of Protection,” as well as some of the redundancy methods and requirements described in PRC-012-2 (for RAS systems), which is subject to future enforcement. These multiple NERC definitions of acceptable types of redundancy will likely cause confusion in industry.

Likes 0	
Dislikes 0	

Response

5. Do you agree with the inclusion of Table 1 Footnote 13 b. & c. stipulation, “which is not monitored or not reported”, and that it conveys the expectation that the monitoring and reporting is sufficient to result in prompt remediation addressing the failure status of the associated equipment?

Mike Smith - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
It is questionable how monitoring will help in the case of a single protection channel. If the monitoring indicated the channel was not available, would the transmission line be taken out of service? The problem is how reliable is the monitoring? The concern is the case when a fault occurs and the single communication system fails. If monitoring is secure and the system can handle an outage of the line to fix the communication system, it's not a bad strategy to save cost.	
Likes 1	Manitoba Hydro , 5, Xiao Yuguang
Dislikes 0	
Response	

Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
AEP seeks clarity regarding the intent of the use of the terms “not monitored or not reported.” Is the intent of the SDT to align with alarming and monitoring functions outlined in PRC standards? Furthermore, it appears that if the components are either monitored OR reported (but not both) it would meet the intent of Footnotes 13b & c. As proposed in the proposed draft, an entity would only have to monitor but not have to report or annunciate for the abnormal conditions specified in Footnote 13a & 13b.	
Likes 0	
Dislikes 0	
Response	

Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
Answer	No
Document Name	
Comment	

The item labels in TPL-001-5 are Footnote 13 2. & 13 3., not Footnote 13 b. & 13 c. We agree with having a single communications system item in Footnote 13. However, we suggest limiting applicable communications systems to those that were installed specifically to assure crucial Normal Clearing times. We agree with having a single DC supply associated with protective functions item in Footnote 13 and with exempting those single DC supplies that are monitored or report both open voltage and open circuit.

Likes 0	
Dislikes 0	

Response

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins

Answer	No
Document Name	

Comment

NVE would like to see more clarification with monitoring and reporting. The frequency and definition of the monitoring should be more specific. If an entity inspects a substation once a year, and considers that as monitoring the DC supply, that does not seem like an effective method for excluding a study of a non-redundant DC supply since the DC supply could then fail within the year period and wouldn't be known until the next inspections. Adding some wording that defines monitoring and reporting would eliminate any confusion. An example would be "alarming for failure within 24 hours of detection to a location where corrective action can be intitiated."

Likes 0	
Dislikes 0	

Response

Kayleigh Wilkerson - Lincoln Electric System - 5

Answer	No
Document Name	

Comment

Although supportive of the stipulation, LES recommends the following change to Footnote 13c to better clarify expectations.

A single dc supply associated with protective 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.***

Likes 0	
Dislikes 0	

Response

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
The terms “monitored” and “reported” need to be fleshed out more. For example, communication circuits can be monitored continuously, daily, weekly, or monthly. What level of monitoring qualifies? The term “reported” could be to an annunciator panel in a station that may be monthly reviewed or it could be to an operations center that is staffed 24/7. See PRC-005-6 Tables 1-2, 1-4, and 2 for examples of how these terms can be used more clearly. We suggest the SDT consider defining these terms as they are used in multiple standards now.	
Likes 0	
Dislikes 0	
Response	

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	No
Document Name	
Comment	
Using the term "reported" is confusing given the expectation that remediation of a failure status is "prompt". Other standards have already established terms for what is considered "monitored", such as PRC-005. Can we not rely on these established concepts?	
Likes 0	
Dislikes 0	
Response	

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
The item labels in TPL-001-5 are Footnote 13 2. & 13 3., not Footnote 13 b. & 13 c. We agree with having a single communications system item in Footnote 13. However, we suggest limiting applicable communications systems to those that were installed specifically to assure crucial Normal Clearing times. We agree with having a single DC supply associated with protective functions item in Footnote 13 and with exempting those single DC supplies that are monitored or report both open voltage and open circuit.	

Likes 0	
Dislikes 0	

Response

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer	No
Document Name	

Comment

Please see comments submitted by Robert Blackne

Likes 0	
Dislikes 0	

Response

Ellen Oswald - Midcontinent ISO, Inc. - 2

Answer	No
Document Name	

Comment

With regard to communication-assisted protection system where a communication signal is required for tripping and normal clearing, this should be considered a single-point-of-failure regardless of whether or not it is monitored. So the answer is NO for Footnote 13.b. With regard to DC supply, since there is some redundancy between the battery and the battery charger, the answer is YES for Footnote 13.c, but there should be additional language that requires separate protection (fuse or circuit breaker) for the battery and the battery charger so once can operate without the other.

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 Dominion

Answer	No
Document Name	

Comment

The PC or TP will be able to determine if communication systems and DC supplies are monitored but it will not know if they are reported. It is presumed that if they are monitored they are reported.

Please consider eliminating the requirement to monitor and report “open circuit” conditions, since such conditions would be tested and maintained per NERC Reliability Standard PRC-005 ‘Protection System, Automatic Reclosing, and Sudden Pressure Relaying’. We believe that preventive maintenance per PRC-005 provides reasonable and sufficient assurance for detection and handling “open circuit” conditions.

Likes 0	
Dislikes 0	

Response

Greg Davis - Greg Davis On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Greg Davis

Answer	No
Document Name	

Comment

Footnote 13 is numbered and not lettered. GTC feels that "which is not monitored or not reported" is not clearly defined. There needs to be a timing frequency as to how the equiment is monitored and when an action will be required to mitigate/correct the problem.

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

We agree with the concept as layed out in the question. However, the bullet points do not match up with the documents reviewed (13.2&3 vs 13.b&c).

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

The above question misidentifies items 2 and 3 of footnote 13 as letters “b” and “c.” We concur that the meaning of “not monitored or reported” regarding a single communications system or dc supply associated with protective functions does convey an expectation that operating personnel who are monitoring such equipment will initiate field remediation activities to mitigate a failure. However, the proposed footnote should limit the inclusion of these Protection System components to only critical sites and at the discretion of the PC or TP.

Likes 0	
Dislikes 0	

Response

John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson

Answer	No
Document Name	

Comment

ISO-NE agrees that a monitored dc supply is sufficient to achieve prompt remediation to address the failure as described in Footnote 13-3. ISO-NE suggests modifying 13-3 to read as follows:

3. A single dc supply associated with protective functions necessary for Normal Clearing, and that single station dc supply is not monitored or not reported for both low voltage and open circuit;

The proposed language above is more consistent with 13-2.

Likes 0	
Dislikes 0	

Response

Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1

Answer	No
Document Name	

Comment

We agree with the inclusion of this wording, with the exception of c. “…for both low voltage and open circuit.” Our DC supplies are monitored, but only for voltage level and not for open circuit.

Likes 0	
Dislikes 0	

Response

Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	No
Document Name	
Comment	
The item labels in TPL-001-5 are Footnote 13 2. & 13 3., not Footnote 13 b. & 13 c. We agree with having a single communications system item in Footnote 13. However, we suggest limiting applicable communications systems to those that were installed specifically to assure crucial Normal Clearing times. We agree with having a single DC supply associated with protective functions item in Footnote 13 and with exempting those single DC supplies that are monitored or report both open voltage and open circuit.	
Likes 0	
Dislikes 0	
Response	

Fred Frederick - Southern Indiana Gas and Electric Co. - 3	
Answer	No
Document Name	
Comment	
We agree with the inclusion of this wording, with the exception of c. "…for both low voltage and open circuit." Our DC supplies are monitored, but only for voltage level and not for open circuit.	
Likes 0	
Dislikes 0	
Response	

Chris Scanlon - Exelon - 1	
Answer	No
Document Name	
Comment	
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. We recommend removing communication systems from footnote 13 in the revised standard.	
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	
No Comments	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts	
Answer	Yes
Document Name	
Comment	
Note: In the "Redline to Last Approved" version of the standard that is posted on the project page, the subparts of Footnote 13 are numbered, not lettered.	
Likes 0	
Dislikes 0	
Response	
Long Duong - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
SNPD does not have additional comments.	
Likes 0	
Dislikes 0	
Response	

Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	Yes
Document Name	
Comment	
Agree.	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
We agree with having a single communications system item in Footnote 13. However, we suggest limiting applicable communications systems to those that were installed specifically to assure crucial Normal Clearing times. We agree with having a single DC supply associated with protective functions item in Footnote 13 and with exempting those single DC supplies that are monitored or report both open voltage and open circuit.	
Likes 0	
Dislikes 0	
Response	
Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
CenterPoint Energy agrees that the inclusion of Table 1 Footnote 13 b. & c. stipulation, “which is not monitored or not reported,” conveys the expectation that the monitoring and reporting is sufficient to result in prompt remediation addressing the failure status of the associated equipment. However, instead of utilizing this newly drafted wording for monitoring, CenterPoint Energy suggests using the wording that is included in the Standard Authorization Request (SAR) as follows: “with alarms centrally monitored (i.e., reported within 24 hours of detecting an abnormal condition to a location where corrective action can be initiated).” This wording in the SAR related to monitoring of Protection Systems has been previously approved by stakeholders and regulators for NERC Standard PRC-005, Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance.	

Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2, Group Name IRC Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Note: MISO does not support this comment.	
Likes 0	
Dislikes 0	
Response	
Haley Sousa - Public Utility District No. 1 of Chelan County - 5, Group Name Chelan PUD	
Answer	Yes
Document Name	
Comment	
If the communication system or DC supply is being monitored, then it is not a single point of failure because the monitoring would have to be lost and an equipment failure would have to occur.	
Likes 0	
Dislikes 0	
Response	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3	
Answer	Yes
Document Name	
Comment	
If the communication system or DC supply is being monitored, then it is not a single point of failure because the monitoring would have to be lost and an equipment failure would have to occur.	
Likes 0	

Dislikes 0	
Response	
Janis Weddle - Public Utility District No. 1 of Chelan County - 6	
Answer	Yes
Document Name	
Comment	
If the communication system or DC supply is being monitored, then it is not a single point of failure because the monitoring would have to be lost and an equipment failure would have to occur.	
Likes 0	
Dislikes 0	
Response	
John Seelke - LS Power Transmission, LLC - 1	
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	

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
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	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe McClung - JEA - 1,3,5 - FRCC, Group Name JEA Voters	
Answer	Yes
Document Name	
Comment	
Likes 1	JEA, 5, Babik John
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	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Anderson - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lynn Goldstein - PNM Resources - Public Service Company of New Mexico - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 4	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Giles - Westar Energy - 1	
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	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
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	
Payam Farahbakhsh - Hydro One Networks, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 1	Hydro One Networks, Inc., 3, Malozewski Paul
Dislikes 0	

Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 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	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
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	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1,5, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5	
Answer	
Document Name	
Comment	
Please see comments of Joe O'Brien NIPSCO.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
As stated in its comments regarding the SAR, Texas RE noticed the proposed language for Footnote 13 does not match the NERC Glossary term of Protection System. Texas RE recommends Footnote 13 align with the NERC Glossary term as well as the monitoring and alarming attributes specified in PRC-005-6 to promote consistency.	
Likes 0	
Dislikes 0	
Response	

6. Do you agree with the inclusion of Table 1 Footnote 13 d., and that it, in conjunction with defined terms, identifies what constitutes all of the elements of, "A single control circuitry associated with protective functions including the trip coil(s) of the circuit breakers or other interrupting devices."?

Leonard Kula - Independent Electricity System Operator - 2

Answer	No
Document Name	

Comment

We recommend treating trip coils in the same fashion as protective relays, communication systems and DC Supply, meaning that a single trip coil which is monitored and reported meets the redundancy requirement.

Likes 0	
Dislikes 0	

Response

John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson

Answer	No
Document Name	

Comment

The language in Table 1 Footnote 13-4 that addresses single control circuitry is unclear. Therefore, ISO-NE proposes revising the language as follows:

4. Any single control circuitry from the dc supply through the relay to the trip coil of the circuit breakers or other interrupting devices.

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

We believe the inclusion of interrupting device trip coils could impact many elements and be outside the intent of a single point of failure analysis. We believe the analysis should only be limited to auxiliary relay 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	
A more explicit definition of the control circuitry is needed. Does this include the cables, auxiliary relays, cable routing? The cables are routed in a controlled environment, therefore have less exposure. Lockout relays and trip coils are monitored for integrity of the trip coil path. Does this eliminate the need for separate control circuitry? Our interpretation is that a shared controlled circuit as defined would need to meet clearing time concerns as defined, each relay function requiring a separate control circuit.	
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 Dominion	
Answer	No
Document Name	
Comment	
Non-redundant components should not consider a single trip coil. Consaidering the trip coil goes beyond non-redundancy of the protection system, in essence the SDT is considering non-redundancy of circuit breakers or other interrupting devices. Please clarify what constitutes “control circuitry.” Please consider adding text from (or referring to) relevant technical rationale document(s), which describes the applicable portions of a “Protection System” as defined in the NERC Glossary of Terms.	
Likes 0	
Dislikes 0	
Response	
Payam Farahbakhsh - Hydro One Networks, Inc. - 1	
Answer	No
Document Name	

Comment	
We recommend treating trip coils in the same fashion as protective relays, communication systems and DC Supply, meaning that a single trip coil which is monitored and reported meets the redundancy requirement.	
Likes 1	Hydro One Networks, Inc., 3, Malozewski Paul
Dislikes 0	
Response	
Robert Ganley - Long Island Power Authority - 1	
Answer	No
Document Name	
Comment	
We feel that it is possible that the revised Table 1 Footnote 13 d helps to identify what constitutes all of the elements of, “A single control circuitry associated with protective functions including the trip coil(s) of the circuit breakers or other interrupting devices.” However, considering the complexities of Footnote 13 d, sample, or representative protection system diagrams and circuitry that would constitute examples of non-redundant components of a Protection System would be helpful. Such diagram(s) are recommended, and would provide clarity in a similar fashion as the diagrams provided in the NERC BES Reference Document.	
Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	
Please see comments submitted by Robert Blackne	
Likes 0	
Dislikes 0	
Response	

Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Monitoring trip coils will ensure that the circuit breaker will trip but as the drafting team points out, it will not ensure that all the electromechanical lockouts (#86) nor the tripping auxiliary relays (#94) will work properly. While it is correct that PRC-005 monitoring does not include electromechanical lockouts (#86) nor tripping auxiliary relays (#94), these components are tested independently as prescribed by PRC-005 to ensure they are working properly. If the transmission system should be designed to be resilient against electromechanical lockout failure or tripping auxiliary relay failure, it doesn't make sense to include testing requirements under PRC-005. Conversely, if we require the industry to test these components, it is extraneous to build the system to be resilient to failure of these components. The number of low-probability events that must simultaneously occur already stretches the bounds of what is reasonable to justify grid expansion (through redundancy or other projects). PRC-005 is already a mitigating activity to the probability of those events and trip coils that are monitored in real-time should be excluded from footnote 13 d.	
Likes 0	
Dislikes 0	
Response	

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
The item label in TPL-001-5 is Footnote 13 4, not Footnote 13 d. We agree with having a single control circuitry item in Footnote 13. However, we suggest replacing reference to interrupting device trip coils with reference to auxiliary relays in the interrupting device control circuity. The failure of an auxiliary relay in an interrupting device trip circuit may result in the tripping of more elements than P4 events (fault plus stuck breaker). The simulation of a single interrupting device trip coil failure is expected to be the same as the simulation of a P4 (fault plus stuck breaker) category event.	
Likes 0	
Dislikes 0	
Response	

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	No
Document Name	
Comment	

The wording in this bullet is somewhat confusing. We recognize that a, b, c, and d in footnote 13 are an attempt to adapt the definition of Protection System, and the original text was "DC control circuitry associated with protective functions through the trip coils…". However, now that we have added "single" to the phrase – it is a single control circuit, or a single portion of a control circuit, to which we are referring? "Single control circuitry" appears to be a mix of singular and plural contexts, or even a mix of a context which is specific to a quantity with one which is inherently both singular and multi-faceted. The SPCS report, page 11, recommended using "(3) DC control circuitry associated with protective functions…" which we would take to mean "the intended outcome of the DC control circuit associated with a protective function, or associated with multiple protection functions, does not come to pass". In this way, it can be adapted to any circuit design by the engineer, applying sound engineering judgment, to determine whether there are any portions of that circuit which may result in significant "failure to perform" outcome. With the term "single" the sentence could be read to mean "the entirety of the control circuit, including every component" since "circuitry" is both singular and multi-faceted in its use. Also, in other standards, DC control circuitry is inclusive of certain auxiliary relays, but this is not clear in the statements added. We suggest either sticking with the original language recommended from the SPCS or using one of the adaptations we've written above to clarify that the engineer should review the components (segments, sub-sections, branch connections – select as you see fit) of each control circuit to look for portions of any circuit associated with a protective relay whose failure could result in more circuit performance failures than just that of one protective relay.

Likes 0	
Dislikes 0	

Response

sean erickson - Western Area Power Administration - 1

Answer	No
Document Name	

Comment

We agree with having a single control circuitry item in Footnote 13. However, we suggest replacing reference to interrupting device trip coils with reference to auxiliary relays in the interrupting device control circuity. The failure of an auxiliary relay in an interrupting device trip circuit may result in the tripping of more elements than P4 events (fault plus stuck breaker). The simulation of a single interrupting device trip coil failure is expected to be the same as the simulation of a P4 (fault plus stuck breaker) category event.

Likes 0	
Dislikes 0	

Response

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins

Answer	No
Document Name	

Comment

The scenario described in Footnote 13d is the exact scenario studied under Category P4. Failure of a single trip coil in a breaker would result in the exact same scenario as a stuck breaker during a fault. Studying a P4 event and a P5 event for Footnote 13d would result in the same contingency. NVE feels that Footnote 13d should be removed and Footnote 10 be modified to include scenarios such as single trip coils.

Likes 0	
Dislikes 0	

Response

Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6

Answer	No
Document Name	

Comment

The item label in TPL-001-5 is Footnote 13 4, not Footnote 13 d. We agree with having a single control circuitry item in Footnote 13. However, we suggest replacing reference to interrupting device trip coils with reference to auxiliary relays in the interrupting device control circuity. The failure of an auxiliary relay in an interrupting device trip circuit may result in the tripping of more elements than P4 events (fault plus stuck breaker). The simulation of a single interrupting device trip coil failure is expected to be the same as the simulation of a P4 (fault plus stuck breaker) category event.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	No
Document Name	

Comment

As similarly requested in previous comment periods, AEP once again requests additional clarification of footnote 13.4 regarding the phrase "Including the trip coil(s) of the circuit breakers or other interrupting devices." For example, 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. In addition, the NERC System Protection and Control Task Force Technical Paper 'Protection System Reliability Redundancy of Protection System Elements', provides the following clarification: "A properly designed breaker failure scheme meeting all the requirements of the TPL standards and the proposed Protection System redundancy requirements could be used to overcome a breaker with only one trip coil or two trip coils operated in parallel." As a result, AEP requests the previous clarification text be added to footnote 13.4 : **"A properly designed breaker failure scheme meeting all the requirements of the TPL standards and the proposed Protection System redundancy requirements could be used to overcome a breaker with only one trip coil or two trip coils operated in parallel."**

Please note that AEP has chosen to vote Negative on TPL-001-5, in part driven by our concerns as provided in our response to Question #6.

Likes 0	
Dislikes 0	

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA believes that regarding a non redundant single trip coil resulting in a breaker not acting as appropriate, there are other contingency categories that require us to plan for breaker failure such as Category P2 and P4. BPA believes this should not be noted in the footnote and "13d" should be removed.	
Likes 0	
Dislikes 0	
Response	

Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts	
Answer	No
Document Name	
Comment	
AECI does not agree with the inclusion of Table 1, Foodnote 13 d., the scope of this footnote is too broad.	
Likes 0	
Dislikes 0	
Response	

Fred Frederick - Southern Indiana Gas and Electric Co. - 3	
Answer	No
Document Name	
Comment	
We feel there is still some question as to what this does and does not include. The example of single control circuitry for a trip coil seems to potentially have the same consequence as a category P4 stuck breaker contingency in that the breaker-fail scheme would initiate.	
Likes 0	
Dislikes 0	
Response	

Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	No
Document Name	
Comment	
The item label in TPL-001-5 is Footnote 13 4, not Footnote 13 d. We agree with having a single control circuity item in Footnote 13. However, we suggest replacing reference to interrupting device trip coils with reference to auxiliary relays in the interrupting device control circuity. The failure of an auxiliary relay in an interrupting device trip circuit may result in the tripping of more elements than P4 events (fault plus stuck breaker). The simulation of a single interrupting device trip coil failure is expected to be the same as the simulation of a P4 (fault plus stuck breaker) category event.	
Likes 0	
Dislikes 0	
Response	

Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1	
Answer	No
Document Name	
Comment	
We feel there is still some question as to what this does and does not include. The example of single control circuitry for a trip coil seems to potentially have the same consequence as a category P4 stuck breaker contingency in that the breaker-fail scheme would initiate.	
Likes 0	
Dislikes 0	
Response	

Greg Davis - Greg Davis On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Greg Davis	
Answer	Yes
Document Name	
Comment	
Yes, however Footnote 13 is numbered and not lettered.	
Likes 0	
Dislikes 0	
Response	

Ellen Oswald - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	
Comment	

With regard to whether or not Footnote 13.d should be included, the answer is Yes, we believe DC control circuitry should be included as a potential single point of failure. However, we believe the language should be expanded to explicitly include auxiliary relays and lockout relays as part of the DC control circuitry for clarity. Furthermore, the DC control circuitry should be further characterized as “tripping DC control circuitry required for Normal Clearing” so that it is clear that single point of failure does not apply to DC closing circuitry or other DC circuitry no required for tripping. In addition, the footnote should limit the tripping DC control circuitry required for Normal Clearing to only that part of the circuitry that would prevent both tripping and initiation of breaker failure. To the extent a single point of failure prevents tripping but does not prevent breaker failure initiation, this contingency would be addressed by a P4 stuck breaker contingency. Finally, should there be a single point of failure in the DC control circuitry that prevents tripping of two circuit breakers but allows for breaker failure initiation on the two circuit breakers, this contingency is worse than a P4 contingency since it represents two stuck breakers, and such an event should be simulated as an independent type of single failure mode under the P5 contingency (while more adverse than a single stuck breaker contingency, it may less adverse than a complete system protection failure which could result in longer clearing delays and additional facilities tripped).

Likes 0	
Dislikes 0	
Response	

Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 4	
Answer	Yes
Document Name	
Comment	

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	

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	

However, “Circuitry” is a vague term and it is unclear what is intended. Something clearer would be, “Any single control circuit, auxiliary relay, lockout relay, etc., whose failure would delay or prevent tripping” if this is what is truly intended by the standard.

Likes 0	
Dislikes 0	
Response	
James Anderson - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Yes; however, “Circuitry” is a vague term and it is unclear what is intended. Something clearer would be, “Any single control circuit, auxiliary relay, lockout relay, etc., whose failure would delay or prevent tripping” if this is what is truly intended by the standard.	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
AZPS recommends that the specific language previously removed during Draft 1 (Applies to following relay functions or types…) not be deleted, as it is helpful to have the specifics and there is no clear reason or benefit associated with the proposed deletion.	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	

However, “Circuitry” is a vague term and it is unclear what is intended. Something clearer would be, “Any single control circuit, auxiliary relay, lockout relay, etc., whose failure would delay or prevent tripping” if this is what is truly intended by the standard.

Likes 0	
Dislikes 0	

Response

Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1

Answer	Yes
Document Name	

Comment

Agree.

Likes 0	
Dislikes 0	

Response

Long Duong - Public Utility District No. 1 of Snohomish County - 1

Answer	Yes
Document Name	

Comment

SNPD does not have additional comments.

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

No Comments

Likes 0	
Dislikes 0	

Response

Janis Weddle - Public Utility District No. 1 of Chelan County - 6

Answer	Yes
Document Name	

Comment

Yes, because this is a single point of failure.

Likes 0	
Dislikes 0	

Response

Joyce Gundry - Public Utility District No. 1 of Chelan County - 3

Answer	Yes
Document Name	

Comment

Yes, because this is a single point of failure.

Likes 0	
Dislikes 0	

Response

Haley Sousa - Public Utility District No. 1 of Chelan County - 5, Group Name Chelan PUD

Answer	Yes
Document Name	

Comment

Yes, because this is a single point of failure.

Likes 0	
Dislikes 0	

Response	

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2, Group Name IRC Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Note: MISO does not support this 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 - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
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	
faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Giles - Westar Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lynn Goldstein - PNM Resources - Public Service Company of New Mexico - 1,3	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
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	
Joe McClung - JEA - 1,3,5 - FRCC, Group Name JEA Voters	
Answer	Yes
Document Name	
Comment	
Likes 1	JEA, 5, Babik John
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
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	
Mike Smith - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 1	Manitoba Hydro , 5, Xiao Yuguang
Dislikes 0	
Response	

John Seelke - LS Power Transmission, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1,5, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

As stated in its comments regarding the SAR, Texas RE noticed the proposed language for Footnote 13 does not match the NERC Glossary term of Protection System. Texas RE recommends Footnote 13 align with the NERC Glossary to avoid confusion.

Likes 0	
Dislikes 0	

Response

Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5

Answer	
Document Name	

Comment

Please see comments of Joe O'Brien NIPSCO.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

More clarity on what is in scope would be needed to maintain compliance.

Likes 0	

Dislikes 0	
Response	

7. Do you agree with the proposed changes to Requirement 1, Part 1.1.2 that modify which known outages shall be represented in System models from those "with a duration of at least six months" to those selected by the Planning Coordinator (PC)/Transmission Planner (TP) "in consultation with" their Reliability Coordinators (RCs).

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

Answer	No
Document Name	

Comment

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). 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 addition:

- The RC has no reason to have detailed information on outages in the planning horizon beyond what is in COS
- Having to respond to every entity within the reliability coordinator area could present an unreasonable burden on the RC and provide risk to the PC/TP if they do not respond
- Reducing the 6 month period to something like "outages spanning the entire season under study" would be reasonable. Limitations that arise due to shorter term outages are an operating horizon issue mitigated by operating practices, not a planning horizon issue.

Likes 0	
Dislikes 0	

Response

Mike Smith - Manitoba Hydro - 1

Answer	No
Document Name	

Comment

MH doesn't see the value in requiring consultation with RC. MH provides a list of outages to the RC and it doesn't make sense to ask them to send the list back to us or to ask them to confirm that we should be studying those particular outages.

Likes 1	Manitoba Hydro , 5, Xiao Yuguang
Dislikes 0	

Response

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC

Answer	No

Document Name	
Comment	

The planning assessments are for the Planning Horizon while the RC acts within the Operations Horizon and should not be coordinating the content of planning studies for a disconnected timeframe. Furthermore, this adds a significant burden to the RC and may reduce their focus on more immediate operations.

The language of R1.1.2. also does not provide a clear definition of what types of outages must be considered (e.g. breakers, switches, equipment out for maintenance, etc.).

Likes 0	
Dislikes 0	

Response

Long Duong - Public Utility District No. 1 of Snohomish County - 1

Answer	No
Document Name	

Comment

To require close coordination effort with RCs for outages with a duration of at least six months would be a challenge for base case updates since most planned outages listed on the Coordinated Outage System were tentative plans. Timing and sequential updates would be extremely onerous for PCs and TPs and would be duplicative with operating case development. It would be more practical for SNPD to only review and update base cases to represent system configurations as expected for its annual TPL studies.

Likes 0	
Dislikes 0	

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

BPA has the same comments we had during the unofficial comment period. BPA agrees with moving away from the 6-month fixed duration outages.

However, 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. BPA’s Planning group studies seasons, anything shorter than 3 months seems more like an operational issue than a planning issue. With a duration of only 3 months, there’s a possibility that the outage may not occur simultaneously with the peak for the season. This would not enhance reliability.

Likes 0	
Dislikes 0	

Response

Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1

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.

We recommend the Requirements 1.1.2 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.

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

Thomas Foltz - AEP - 5

Answer	No
Document Name	

Comment

This new “consultation” requirement necessitates a correspondence documentation trail that further burdens TP and PC compliance with this already overly complex standard. It is administrative in nature and provides no benefit to the reliability of the BES. We believe that the TP and PC are just as capable to select from the known outages as the RC, and that any consultation with the RC should be at the TP’s or PC’s discretion.

In addition, 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.

Likes 0	
Dislikes 0	

Response

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 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 is currently an Extreme event, which was never intended.

Further, clarification needs to be given on the meaning of "consultation" and who has the final responsibility of what outage (if any) needs to included in the study models.

Likes 0	
Dislikes 0	

Response

Michelle Amarantos - APS - Arizona Public Service Co. - 1

Answer	No
Document Name	

Comment

AZPS does not agree with the proposed changes to Requirement 1, Part 1.1.2. AZPS asserts that, giving due consideration to Requirement R4 of IRO-017-1, which came after FERC Order 786, the need to revision Part 1.1.2 has been mooted and is no longer necessary. For this reason, AZPS recommends removal of this requirement.

More specifically, Requirements R3 and R4 of IRO-017 already require coordination between the PC, TP and RC regarding outages in the planning assessment and also requires jointly developed solutions. Thus, the coordination contemplated in Requirement 1, Part 1.1.2 should have already occurred and should not need or be required to re-occur. In fact, AZPS respectfully asserts that the earlier outage and solution coordination occurring as a result of IRO-017 sets up exactly the right process in terms of timing to ensure that outages and solutions are timely, appropriately, and rigorously evaluated. Allowing this coordination to occur in the natural course of operations and not requiring redundant coordination will result in more touch points among the identified entities, facilitating a greater mutual understanding of those outages that would be more impactful to the BES, which understanding better informs the assumptions shaping the inclusion of outages as required by Requirement 1, Part 1.1.2.

For this reason, AZPS respectfully asserts that the coordination and joint solution development requirement included in Requirement 1, Part 1.1.2 be deleted. The inclusion of another coordination and joint solution development beyond that which is required by IRO-017 is not only redundant, but introduces the potential for confusion and ambiguity. Further, the creation of an additional obligation for RC, TP and PC coordination and joint solution development would be simply redundant and would not add enough value to reliability to justify the additional expenditure of resources. Finally, revisiting previous outage coordination and joint solution development would not be cost-effective for any of the involved entities. AZPS recommends removal of the requirement for outage coordination and joint solution development as set forth in Requirement 1, Part 1.1.2.

AZPS further recommends (this is only if deletion is not acceptable) that, since coordination and joint solution development are already occurring under IRO-017, the language of Requirement 1, Part 1.1.2 be revised to state a definitive time period. AZPS respectfully suggests that a 3 month time period for outages is a conservative time period for the inclusion of outages and recommends this time frame as it is generally aligns with those outage time frames that would be considered impactful in the performance of seasonal studies. AZPS recommends the following revisions:

1.1.2 Known outage(s) of generation or Transmission Facility(ies) with a duration of three months for the Near -Term Planning Ho for analyses pursuant to Requirement R2, parts 2.1.3 and 2.4.3.

If the language is retained as it is, AZPS respectfully requests that the RC be added as an applicable functional entity to this standard as there is nothing to obligate the Reliability Coordinator to respond within a required period of time, which could affect the Transmission Provider or Planning Coordinator's ability to complete the work in time.

Likes 0	
Dislikes 0	

Response

Joe McClung - JEA - 1,3,5 - FRCC, Group Name JEA Voters

Answer	No
Document Name	

Comment

The proposed TPL-001-5 standard is applicable only to PC and TP per the Applicability section. But RC is NOT under compliance requirement for this action since the standard is NOT applicable to them. The proposed changes add extra burden on the PC and TP for compliance on which they have no control. Any inaction from RC (non-consultation) can expose PC and TP to possible violation with this part of the requirement.

Moreover, the outage coordination seems to be more of an Operational Planning issue (from the next-day studies up to a year out) than a Transmission Planning issue (beyond year one to year ten studies). No matter how far ahead PC and TP 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 PC and TP for the outages in the Planning Horizon don't provide much value to the system operators in the Operation horizon.

Additionally, if the system can't meet the performance requirements due to outages as per R2.1.3 and R2.4.3, the TP and PC 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 IRO-017 Outage Coordination standard is a much better venue to address FERC's concern from Paragraph 40 of Order No. 786 and TPL-001 standard should be maintained solely as a true Transmission Planning Standard. Besides, this directive pre-dates IRO-017 standard and is not relevant anymore under the proposed TPL-001-5 for outage coordination with durations less than six months.

Suggestion: Keep the existing language of R1.1.2 unchanged from TPL-001-4 and address Paragraph 40 directive with revision of IRO-017.

Likes 1	JEA, 5, Babik John
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

We believe that any reference to the RC should be removed from this planning standard. Order 786, paragraph 42, clearly states to "include **known** genertor and transmission planned maintenance outages in planning assessments, not hypothetical planned outages." The RC at best has clear visibility of "known" outages for a period of less than one year. The state of the transmission system in the RC environment is based on "real-time" conditions, which are not conducive of conditions reflected in planning models used in assessments for the near-term or the long-term planning horizons. We suggest changing the language of the requirement to "Known outage(s) of generation or Transmission Facility(ies) occuring within the timeframe of the seasonal models or scenarios used in the analyses, pursuant to Requirement 2, parts 2.1.3 and 2.4.3." This allows for the modeling of "known" outages in any model during both peak and off-peak conditions, which include timeframes when maintenance on transmission facilities can take place based on the models which are developed.

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	No
Document Name	

Comment

We do 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 horizon. For those Reliability Coordinators with a significant number of TPs and PCs in their footprint, this requirement change would add a significant burden on the RCs without benefit to the process. The focus of the RC is in the real-time to one year horizon, whereas Transmission 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 TP, it should be the role of the PC.

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 siginificant new effort and time to complete.

Likes 0	
Dislikes 0	

Response

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins

Answer	No
Document Name	

Comment

NVE agrees that outages of less than 6 months should be considered, but does not agree that consultaion with the RC is necessary. A list of outages is provided to the RC by an entity, this consultation would require the entity get that list back and ask them to confirm that we should be studying those particular outages. Further, depending on the number of TP's/PC's, asking the RC to consult with each of them could place an unreasonable burden on the RC and place risk to the PC/TP if they do not respond and also necessitates a documentation trail that would further burden the PC/TP. NVE suggests changing the requirement to outages that span the season under study or other outages as determined by the TP/PC.

Likes 0	
Dislikes 0	

Response

sean erickson - Western Area Power Administration - 1

Answer	No
Document Name	

Comment

WAPA understands that the drafting team has chosen this language in an attempt to provide flexibility to the TPs and PCs conducting their TPL Assesment. WAPA supports the need to change the language due to the concern of missing potential critical outages of equipment because the outage does not fall within the "duration of at least six months". If there are known critical outages that cannot be taken out of service under a significant portion of the year (ex: even under light load levels), a Corrective Action Plan is reasonable. In other words, WAPA supports that a properly planned transmission system should ensure that the known planned removal of facilities for maintenance purposes can occur without the loss of non-consequential load or detrimental impacts to system reliability.

The concern is that with the existing proposed language, what information is the RC going to provide for this requirement? Will it be a dump of all non-concurrent outages that are scheduled, which may require the TP/PC conducting the TPL Assessment to spend unneccary efforts in justifying why a specific outage should not be included in a TPL study model? Furthermore, RC's likely will not have knowledge of critical outages that could occur further into the future, but are still within the near term planning horizon (up to 60 months into the future). In reality, for the purposes of TPL studies, it is these critical outages further into the future that are important because when identifying areas where Corrective Action Plans are needed it is important to identify them with sufficient lead time available to implement them.

A possible suggestion to consider would be to change the language by saying that the System models shall represent known critical planned maintenance outage(s) of generation or Transmission Facility(ies) that are expected to have a detrimental impact to system reliability in the Near-Term Planning Horizon for analysis pursuant to Requirement R2, parts 2.1.3 and 3.4.3. The rationale for those critical outage(s) selected for inclusion shall be available as supporting information.

Likes 0	
Dislikes 0	

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	

Comment

The concept of known or planned outages needs to have a footnote or further explanation to clarify that this applies to “outages needed to execute the CAP” and be very specific. Maintenance outages should not be addressed in this TPL standard. Maintenance outages are typically not known much more than 6 months out and are assessed by Operations Planning, under TOP and/or IRO standards, closer to the desired time of the maintenance outage such that expected system conditions reflected in the study power flow is better known.

Our expereince in outage planning has shown that it is very unlikely that “planned” transmission outages exist beyond the next six months and that generator outage schedules are changed frequently. Additionally, to model outages that are expected to last a few weeks to two months into power flow cases that can cover 2-4 months is problematic. The reason is that multiple “potential impactful outages” will likely be identified as canidates to include in the base system power flow model. However, in reality these outages probably don’t overlap thus presenting a complication in selecting what to include in the base system power flow model. Operations Planning builds cases on a daily and weekly basis to assess the impact of planned outages whilch is not practical in the TPL arena. If the Standard stated outages that span the duration of the season being studied that would make this straight forward and remove the RC.

While we recognize that the RC is not an applicable entity in this draft of the standard, involving the RC at all in the Requirements 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.

If the RC remains included in the Requirement, need to add words to make it clear that the TP/PC can choose 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 is not electrically close to generation and not in an area susceptible to FIDVR

Likes 0	
Dislikes 0	

Response

Quintin Lee - Eversource Energy - 1	
Answer	No
Document Name	
Comment	

We agree with the change except that the Requirement should specifically quantify the time period in which the known outage(s) must be scheduled in order to be considered by the RC, PC, and TP. We feel that Requirement 1, Part 1.1.2 should be written as:

Known outage(s) of generation or Transmission Facility(ies) expected to occur beginning after 12-months from the start of an assessment and beginning before the end of the Near-Term Planning Horizon, as selected in consultation with the Reliability Coordinator for analyses pursuant to Requirement R2, parts 2.1.3 and 2.4.3.

Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	No
Document Name	
Comment	

This requirement places an additional burden on the PC, TP, and RC without any demonstrated benefit to system reliability. Any outage that would be studied as part of the Planning Assessment would be beyond the Operational Planning time horizon. The concept of performing outage planning as part of a Planning Assessment would be difficult to accomplish. In general, maintenance outages are scheduled to minimize the impacts to the system. Depending on the entity's Off-Peak conditions it may be appropriate to include a planned maintenance outage that occurs at regular intervals. However, the RC would not have any insight into how each individual GO and TO schedules maintenance outages. PNM recommends the FERC approach of removing the 6 month threshold from the requirement.

Additionally, the standard as written does not make clear what CAP would be expected if an entity's planned outage results in a system performance violation? Would the standard permit an acceptable CAP to delay the outage or would the standard require transmission improvements are made to address any system performance violations? PNMR recommends the SDT consider making necessary changes to address these ambiguities.

The RC should use IRO-017 to address any concerns they have about planned outage which might mean expanding operations studies to include multiple category events from TPL-001-4.

Likes 0	
Dislikes 0	
Response	
Lynn Goldstein - PNM Resources - Public Service Company of New Mexico - 1,3	
Answer	No

Document Name	
Comment	

I support PNM's comments.

Likes 0	
Dislikes 0	
Response	

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer	No
Document Name	
Comment	

FMPA agrees with JEA's comments.

Likes 0	
Dislikes 0	
Response	

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer	No
Document Name	
Comment	

Please see comments submitted by Robert Blackne

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 changes to Requirement 1, Part 1.1.2 that the outages represented in System models be selected “in consultation with” Reliability Coordinators (RCs). CenterPoint Energy recommends that Reliability Coordinators (RCs) not be added as an applicable Functional Entity. CenterPoint Energy recommends that TPL-001-5 be applicable only to Planning Coordinators (PCs) and Transmission Planners (TPs).

CenterPoint Energy recommends deleting the reference to Reliability Coordinators (RCs) in Part 1.1.2 as follows:

“Known outage(s) of generation or Transmission Facility(ies) for the Near Term Planning Horizon irement R2, parts 2.1.3 and 2.4.3.”

Likes 0	
Dislikes 0	
Response	
Robert Ganley - Long Island Power Authority - 1	
Answer	No
Document Name	
Comment	

We feel that the proposed language is too subjective and open to interpretation. The idea of “consulting” with the RC to identify known outages adds to the lack of objectivity in identifying known outages and increases the level of complexity in identifying known outages. We believe this concept does not provide clear compliance ownership for the identification of known outages and believe this will make demonstration of compliance by the Transmission Planner unduly complex.

Likes 0	
Dislikes 0	
Response	
Ellen Oswald - 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 robustness and 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 meet 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 and TPL-001-5 standards.

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 schedule 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

Payam Farahbakhsh - Hydro One Networks, Inc. - 1

Answer	No
Document Name	

Comment

We disagree with replacing “planned outages of 6 months or more” in Part 1.1.2 with “as selected in consultation with the Reliability Coordinator for the Near **-Term Planning Horizon for**

The coordination of outages in the Near-Term Planning Horizon between RC, PC and TP is already required by Requirement R4 of IRO-017-1, therefore it should not be duplicated here.

Likes 1	Hydro One Networks, Inc., 3, Malozewski Paul
Dislikes 0	

Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion	
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.

We recommend the Requirements 1.1.2 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) 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.

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.

We agree with the change except that the Requirement should specifically quantify the time period in which the known outage(s) must be scheduled in order to be considered by the RC, PC, and TP. We feel that Requirement 1, Part 1.1.2 should be written as:

Known outage(s) of generation or Transmission Facility(ies) expected to occur beginning after 12-months from the start of an assessment and beginning before the end of the Near-Term Planning Horizon, as selected in consultation with the Reliability Coordinator for analyses pursuant to Requirement R2, parts 2.1.3 and 2.4.3.

Likes 0	
Dislikes 0	
Response	

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	

While the probability of an unplanned contingency during a short duration (less than six month) planned outage is much lower than during a longer planned maintenance outage period, these types of scenarios are already evaluated and planned for in the TPL-001-4 planning assessment through the various N-1-1 contingency combinations. It is PacifiCorp's opinion that the short-term planned outage scenarios are better addressed in the operating horizon.

Also see WAPA's comments.

Likes 0	
Dislikes 0	
Response	

Greg Davis - Greg Davis On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Greg Davis	
Answer	No
Document Name	
Comment	

GTC does not agree with the proposed changes and agree with the comments provided by Xcel Energy, INC. "We believe that any reference to the RC should be removed from this planning standard. Order 786, paragraph 42, clearly states to "include **known** genertor and transmission planned maintenance outages in planning assessments, not hypothetical planned outages." The RC at best has clear visibility of "known" outages for a period of less than one year. The state of the transmission system in the RC environment is based on "real-time" conditions, which are not conducive of conditions reflected in planning models used in assessments for the near-term or the long-term planning horizons. We suggest changing the language of the requirement to "Known outage(s) of generation or Transmission Facility(ies) occuring within the timeframe of the seasonal models or scenarios used in the analyses, pursuant to Requirement 2, parts 2.1.3 and 2.4.3." This allows for the modeling of "known" outages in any model during both peak and off-peak conditions, which include timeframes when maintenance on transmission facilities can take place based on the models which are developed."

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 re-affirms its concern with adding short term outages to these planning assessments. As written, this standard requires that a PC must consult with the RC and possibly include in studies short term outages with which the PC has no input on or have any responsibility for outside of this requirement. This is better suited in the Operations Planning horizon based on the operational and dynamic nature of outages with a duration of at least six months.

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 SDT is heading in the right direction with the proposed modification. However, the accountability of the RC in the consultation process does not reflect what is already required in NERC Reliability Standard IRO-017-1. As proposed, a PC or TP would need to incorporate any planned outage it became aware of in its Planning Assessment, even if the outage has not yet been processed in an impacted Reliability Coordinator's outage coordination program. Requirement R4 of NERC Reliability Standard IRO-017-1 does require the TP and PC to develop, jointly with their RCs, solutions that resolve issues identified from planned outages included in a Planning Assessment. Moreover, what proof is necessary to demonstrate an applicable entity consulted their RC? Most entities will likely extract approved outage information from a database and not through verbal or electronic communication with their RC. We propose rewording Requirement 1, Part 1.1.2, of the proposed Reliability Standard TPL-001-5 to "outage(s) of generation or Transmission Facility(ies) identified through implementation of its Reliability Coordinator's outage coordination process.
2. We ask the SDT to specify the appropriate RC that should influence an impacted PC's or TP's system model and Planning Assessment. Currently, the proposed language opens the possibility that any RC could provide information regarding a generation or Transmission Facility outage.

Likes 0	
Dislikes 0	
Response	

Leonard Kula - Independent Electricity System Operator - 2

Answer	No
Document Name	
Comment	

We disagree with replacing "planned outages of 6 months or more" in Part 1.1.2 with "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."

The coordination of outages in the Near-Term Planning Horizon between RC, PC and TP is already required by Requirement R4 of IRO-017-1,; therefore it should not be duplicated here.

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

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2, Group Name IRC Standards Review Committee

Answer	No
Document Name	

Comment

The proposed requirement in part 1.1.2 of R1 that TPs and PCs select known outages "in consultation with" their Reliability Coordinators for use in developing planning models creates unnecessary ambiguity. TPs and PCs already have the ability to obtain information about known outages under MOD-032, and TPs and PCs already use that authority in complying with the requirement to include known outages greater than six months long in their planning assessments. So involving the RC in identifying outages for planning models is unnecessary. The "in consultation with" phrasing is also unclear as to the particular efforts required by the TP, PC, and RC. Who bears the burden for the initial communication? What if the RC fails to provide some or all of the outage information? If the RC and TP/PC disagree as to which outages should be included, whose opinion controls? The SRC recommends eliminating this proposed language and instead clarifying the standard to give the TP/PC clear deference in deciding which expected outages should be included in the various planning models. The SRC recommends the following language for part 1.1.2:

1.1.2. Known outage(s) of generation or Transmission Facility(ies) selected by the Transmission Planner or Planning Coordinator in its sole discretion for the Near-Term Planning Horizon for analyses pursuant to Requirement R2, parts 2.1.3 and 2.4.3.

The SRC notes that IRO-017, R4, already requires that "[e]ach Planning Coordinator and Transmission Planner shall jointly develop solutions with its respective Reliability Coordinator(s) for identified issues or conflicts with planned outages in its Planning Assessment for

the Near-Term Transmission Planning Horizon." The SRC recommends removing or clarifying this requirement in a future project, since transmission planning requirements should be captured in the TPL standards and because the RC should, as a general rule, have no role in transmission planning activities.

Note: MISO and ISO-NE do not support this comment.

Likes 0	
Dislikes 0	

Response

Haley Sousa - Public Utility District No. 1 of Chelan County - 5, Group Name Chelan PUD

Answer	No
Document Name	

Comment

The RC is not a Functional Entity in the TPL-001-5 Applicability and has no obligation to comply with this standard. The definition of RC states that the RC prevents/mitigates "operating situations in both next-day analysis and real-time operations." The RCs role is in the operations horizon, not the planning horizon. Thus, RCs should not be consulted for outages represented in the planning horizon, which is beyond the scope of their duties. Including this requirement would add additional burden to entities which would now have to coordinate numerous outages with the RC. This additional step will add risk for entities to comply with this standard as it is another form of communication that may not be fulfilled (as in the RC may not respond). The RC would also have the unreasonable burden of coordinating with numerous entities.

Furthermore, this language does not prevent the RC from requesting hypothetical outages. An RC may request that an outage of a critical facility to be studied during peak conditions, when it is the TO's practice to only take this outage during off-peak conditions due to that very reason. While the use of only "real" known outages is FERC's intent, there is no language in the proposed standard to prevent the RC from requesting a hypothetical outage.

In WECC, the Peak RC COS outage management tool used by the RC does not frequently capture outages out into the planning horizon. Additionally, the Peak RC has implemented an outage coordination process to evaluate outages in the operations horizon to manage these risks.

It is important to understand that much like protection system relaying is both a science and an art, one cannot fully study outages without understanding the nature of outage coordination. CHPD's planning engineers work both on planning studies and operational studies, so we are aware that some outages are planned in the future, but when evaluated, simply won't work under those conditions. The proper mitigation, rather than to create a new project to fix this, is to move the outage to a time when it will work or cause more manageable impacts.

Based on FERC's comments under order 786, paragraph 41, the intent of this re-visit on the 6 month criteria is to address "a single element to be taken out of service for maintenance without compromising the ability of the system to meet demand without loss of load." Given that this is FERC's area of focus, the NERC criteria may consider a criteria in-line with those ends, such as requiring outages that the RC has identified that have required loss of load based on past operational experience. NERC may also consider allowing system adjustments for these outages, as is common with actual operational practice.

Based on FERC's suggestions, a reduced window or definition of a "significant planned outage based, for example, on MW or facility ratings" would be preferred over the outright removal of the 6 month window and the Peak RC additions currently proposed.

Likes 0	
Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
We agree with reducing the duration of known outages from at least 6 months to at least 3 months. However, based on current practices and considering this proposed reduction, it is still doubtful that there would be any planned transmission outages to consider for inclusion in the models for the planning horizon. We do not believe that involving the Reliability Coordinator would lead to any fruitful discussions from a planning perspective.	
Likes 0	
Dislikes 0	
Response	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3	
Answer	No
Document Name	
Comment	

The RC is not a Functional Entity in the TPL-001-5 Applicability and has no obligation to comply with this standard. The definition of RC states that the RC prevents/mitigates “operating situations in both next-day analysis and real-time operations.” The RCs role is in the operations horizon, not the planning horizon. Thus, RCs should not be consulted for outages represented in the planning horizon, which is beyond the scope of their duties. Including this requirement would add additional burden to entities which would now have to coordinate numerous outages with the RC. This additional step will add risk for entities to comply with this standard as it is another form of communication that may not be fulfilled (as in the RC may not respond). The RC would also have the unreasonable burden of coordinating with numerous entities.

Furthermore, this language does not prevent the RC from requesting hypothetical outages. An RC may request that an outage of a critical facility to be studied during peak conditions, when it is the TO’s practice to only take this outage during off-peak conditions due to that very reason. While the use of only “real” known outages is FERC’s intent, there is no language in the proposed standard to prevent the RC from requesting a hypothetical outage.

In WECC, the Peak RC COS outage management tool used by the RC does not frequently capture outages out into the planning horizon. Additionally, the Peak RC has implemented an outage coordination process to evaluate outages in the operations horizon to manage these risks.

It is important to understand that much like protection system relaying is both a science and an art, one cannot fully study outages without understanding the nature of outage coordination. CHPD’s planning engineers work both on planning studies and operational studies, so we are aware that some outages are planned in the future, but when evaluated, simply won’t work under those conditions. The proper mitigation, rather than to create a new project to fix this, is to move the outage to a time when it will work or cause more manageable impacts.

Based on FERC’s comments under order 786, paragraph 41, the intent of this re-visit on the 6 month criteria is to address “a single element to be taken out of service for maintenance without compromising the ability of the system to meet demand without loss of load.” Given that this is FERC’s area of focus, the NERC criteria may consider a criteria in-line with those ends, such as requiring outages that the RC has identified that have required loss of load based on past operational experience. NERC may also consider allowing system adjustments for these outages, as is common with actual operational practice.

Based on FERC's suggestions, a reduced window or definition of a "significant planned outage based, for example, on MW or facility ratings" would be preferred over the outright removal of the 6 month window and the Peak RC additions currently proposed.	
Likes 0	
Dislikes 0	
Response	
Janis Weddle - Public Utility District No. 1 of Chelan County - 6	
Answer	No
Document Name	
Comment	

The RC is not a Functional Entity in the TPL-001-5 Applicability and has no obligation to comply with this standard. The definition of RC states that the RC prevents/mitigates "operating situations in both next-day analysis and real-time operations." The RCs role is in the operations horizon, not the planning horizon. Thus, RCs should not be consulted for outages represented in the planning horizon, which is beyond the scope of their duties. Including this requirement would add additional burden to entities which would now have to coordinate numerous outages with the RC. This additional step will add risk for entities to comply with this standard as it is another form of communication that may not be fulfilled (as in the RC may not respond). The RC would also have the unreasonable burden of coordinating with numerous entities.

Furthermore, this language does not prevent the RC from requesting hypothetical outages. An RC may request that an outage of a critical facility to be studied during peak conditions, when it is the TO's practice to only take this outage during off-peak conditions due to that very reason. While the use of only "real" known outages is FERC's intent, there is no language in the proposed standard to prevent the RC from requesting a hypothetical outage.

In WECC, the Peak RC COS outage management tool used by the RC does not frequently capture outages out into the planning horizon. Additionally, the Peak RC has implemented an outage coordination process to evaluate outages in the operations horizon to manage these risks.

It is important to understand that much like protection system relaying is both a science and an art, one cannot fully study outages without understanding the nature of outage coordination. CHPD's planning engineers work both on planning studies and operational studies, so we are aware that some outages are planned in the future, but when evaluated, simply won't work under those conditions. The proper mitigation, rather than to create a new project to fix this, is to move the outage to a time when it will work or cause more manageable impacts.

Based on FERC's comments under order 786, paragraph 41, the intent of this re-visit on the 6 month criteria is to address "a single element to be taken out of service for maintenance without compromising the ability of the system to meet demand without loss of load." Given that this is FERC's area of focus, the NERC criteria may consider a criteria in-line with those ends, such as requiring outages that the RC has identified that have required loss of load based on past operational experience. NERC may also consider allowing system adjustments for these outages, as is common with actual operational practice.

Based on FERC's suggestions, a reduced window or definition of a "significant planned outage based, for example, on MW or facility ratings" would be preferred over the outright removal of the 6 month window and the Peak RC additions currently proposed.

Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1,5, Group Name LCRA Compliance	

Answer	No
Document Name	
Comment	

For ease of implementation and efficiency and compliance, a bright line criteria such as “at least six months” is appropriate. There is little reliability risk for outages shorter than this duration and the burden imposed by the coordination requirement is not worth the cost.

Likes 0	
Dislikes 0	
Response	

Teresa Cantwell - Lower Colorado River Authority - 5

Answer	No
Document Name	
Comment	

For ease of implementation and efficiency and compliance, a bright line criteria such as “at least six months” is appropriate. There is little reliability risk for outages shorter than this duration and the burden imposed by the coordination requirement is not worth the cost.

Likes 0	
Dislikes 0	
Response	

Kevin Giles - Westar Energy - 1

Answer	Yes
Document Name	
Comment	

Requirement 1, Part 1.1.2 seems to imply that the outages that are selected by the Planning Coordinator (PC)/Transmission Planner (TP) in consultation with their Reliability Coordinators (RCs) should be baked in to the System Models. However, Requirement 2, Part 2.1.3 and Part 2.4.3 indicate that only P1 events should be run on the cases with these outages in place. So, should the outages be removed to perform the studies required under Parts 2.4.1, 2.4.2, and 2.4.4 where we are required to consider P1-P7 and Extreme events? This is a point of the confusion in the current standard as well and we would ask the standard drafting to please clarify.

Likes 0	
Dislikes 0	
Response	

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
ITC believes all combinations (N-1-1) should be considered in planning studies for load levels up to those at which the system is typically maintained. It is imperative that the system is planned so that it can be adequately maintained. While ITC agrees with the proposed changes in outages that should be represented in system models to those selected by the PC/TP in consultation with the RC, ITC feels this would be better if included in IRO-017. ITC also agrees with the proposed changes in outages that should be represented in system models to those selected by the PC/TP in consultation with the RC however ITC feels this would be better if included in IRO-017.	
Likes 0	
Dislikes 0	
Response	
John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson	
Answer	Yes
Document Name	
Comment	
IRO-017 requires the RC to evaluate outages with the PC/TP.	
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 has a concern that the term ‘Off Peak’ currently could be confusing and recommends that the term should be lower case.	
Likes 0	
Dislikes 0	
Response	

John Seelke - LS Power Transmission, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Anderson - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 4	
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	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Fred Frederick - Southern Indiana Gas and Electric Co. - 3	
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	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5	
Answer	
Document Name	
Comment	
Please see comments of Joe O'Brien NIPSCO.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not necessarily agree the drafting team met the intent of FERC Order 786, Paragraph 40, which states "…we direct NERC to modify Reliability Standard TPL-001-4 to address the concern that the six month threshold could exclude maintenance outages of significant facilities from future planning assessments." The proposed language allows excessive flexibility between the RC and TP/PC, especially considering the RC and PC are frequently the same entity. At the very least, Texas RE recommends a criteria be developed with technical justification for long term outages that need to be modeled as well as criteria to determine which maintenance outages need to be studied. The proposed language could result in not selecting any outages and the entities would still be compliant.	

Likes 0	
Dislikes 0	
Response	

8. Do you agree with omitting the Reliability Coordinator (RC) from the applicability of the TPL-001-5 standard given that Requirement R1, Part1.1.2 requires consultation between the TP/PC and the RC to determine which known outages to select for representation in System models?

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 recommends that the drafting team develop some language that includes the Transmission Owners (TOs) and Generation Owners (GOs) to help close the gap on known outages that are outside of the Operating Horizon to be included in Part 1.1.2. However, if the drafting team feels that developing language to include the TO and GO is not the appropriate action, we would also suggest considering IRO-017 as another option to pursue.	
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 that the drafting team consider placing the Reliability Coordinator in the Applicability section of the standard**.**	
Likes 0	
Dislikes 0	
Response	

Greg Davis - Greg Davis On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Greg Davis	
Answer	No
Document Name	
Comment	
No, if consultation with the RC is required in TPL-001-5 then the standard should be applicable to them as well. Also, the reporting requirement R3 in IRO-017-1 should be moved to TPL-001-5.	
Likes 0	

Dislikes 0	

Response

Robert Ganley - Long Island Power Authority - 1

Answer	No
Document Name	

Comment

As stated in our comment above, We feel that the proposed language is too subjective and open to interpretation. We believe the proposed language for 1.1.2 does not provide clear compliance ownership for the identification of known outages.

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

Likes 0	
Dislikes 0	

Response

Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Document Name	

Comment

CenterPoint Energy recommends Reliability Coordinators (RCs) not be added as an applicable Functional Entity. CenterPoint Energy recommends that TPL-001-5 be applicable only to Planning Coordinators (PCs) and Transmission Planners (TPs). CenterPoint Energy disagrees with the proposed changes to Requirement 1, Part 1.1.2 that the outages represented in System models be selected “in consultation with” Reliability Coordinators (RCs).

CenterPoint Energy recommends deleting the reference to Reliability Coordinators (RCs) in Part 1.1.2 as follows:

“Known outage(s) of generation or Transmission Facility(ies) for the Near
and 2.4.3.”

Likes 0	
Dislikes 0	

Response

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer	No
Document Name	

Comment	
Please see comments submitted by Robert Blackne	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	No
Document Name	
Comment	
No, FMPA agrees with JEA's comments for question 7	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
If consultation with the RC is required in TPL-001-5 then the standard should be applicable to the RC. Alternatively, coordination were included in IRO-017 rather than in TPL-001-5 then RC applicability in this standard would not be necessary.	
Likes 0	
Dislikes 0	
Response	
Lynn Goldstein - PNM Resources - Public Service Company of New Mexico - 1,3	
Answer	No

Document Name	
Comment	
I support PNM's comments.	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	No
Document Name	
Comment	
The SDT should consider the situation in the TRE Region where ERCOT is both the PC and the RC. Planned outages are not firmly determined until a few months before they are expected to be implemented. ERCOT currently has no input into a TP's annual assessment until such a time that construction requiring an outage is requested. PNMR views this as a potential Operational issue which should be studied at the appropriate time before requesting/taking an outage. Longer lead-time outage timing can be difficult to reliably include in planning studies due to the degree of unknown variables, such project delays, conflicting outage schedules, and as such may not be able to be reasonably included in long-term planning assessments. Further, PNMR recommends including the RC Registration Function in the Standard's applicability given the RC has responsibilities under the standard.	
Likes 0	
Dislikes 0	
Response	
Jeffrey Watkins - Jeffrey Watkins On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins	
Answer	No
Document Name	
Comment	
If suggestions for R1.1.2 provided in question 7 are not accepted by the SDT, then the applicability of TPL-001 should be expanded to include the RC. Without making the RC applicable, then there is no guarantee that the RC will consult with the TP/PC.	
Likes 0	
Dislikes 0	
Response	

Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	No
Document Name	
Comment	
AZPS only agrees with omitting the Reliability Coordinator if R.1.1.2 is deleted as suggested or modified such that it does not require consultation with the Reliability Coordinator as stated above in response to question 7. If the language is retained as is, AZPS respectfully requests that the RC be added as an applicable functional entity to this standard. Unless the standard is applicable to RCs, there is nothing to obligate the Reliability Coordinator to respond within a required period of time, which could affect the Transmission Provider or Planning Coordinator's ability to complete the assessment work in time. AZPS reiterates its comments provided in response to Question 7.	
Likes 0	
Dislikes 0	
Response	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	No
Document Name	
Comment	
If the SDT does not accept our comment to clarify and revise R1.1.2, 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	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
SRP agrees with the comments provided by Seattle City Light:	

“If the requirement to consult with the RC remains in the standard, then they should be included in the applicability, but we believe that consultation with the RC is inappropriate for this standard.“

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
If the requirement to consult with the RC remains in the standard, then they should be included in the applicability, but we believe that consultation with the RC is inappropriate for this standard.

Likes 0	
Dislikes 0	

Response
Janis Weddle - Public Utility District No. 1 of Chelan County - 6

Answer	No
Document Name	

Comment
If this requirement remains in the standard, the RC should be added to the Applicability section of the standard. CHPD does not agree with the added requirement to coordinate outages with the RC for the planning assessment.

Likes 0	
Dislikes 0	

Response
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3

Answer	No
Document Name	

Comment

If this requirement remains in the standard, the RC should be added to the Applicability section of the standard. CHPD does not agree with the added requirement to coordinate outages with the RC for the planning assessment.	
Likes 0	
Dislikes 0	
Response	
Haley Sousa - Public Utility District No. 1 of Chelan County - 5, Group Name Chelan PUD	
Answer	No
Document Name	
Comment	
If this requirement remains in the standard, the RC should be added to the Applicability section of the standard. CHPD does not agree with the added requirement to coordinate outages with the RC for the planning assessment.	
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 Dominion	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gary Trent - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	Yes
Document Name	
Comment	

Yes. This is a Planning Standard and the RC does not need to be involved as stated in the response to question 7. However, if the RC involvement remains, they should be included in applicability and should have a time requirement to respond (5 business days) to respond to the Planning Coordinator (PC) or Transmission Planner (TP) if they are in agreement with the maintenance outages to be studied as proposed by the PC/TP.

Likes 0	
Dislikes 0	

Response

John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson

Answer	Yes
Document Name	

Comment

ISO-NE believes that it is most cost-effective and efficient for the RC to be a part of outage determinations. IRO-017 should be modified as required to address this consideration.

Likes 0	
Dislikes 0	

Response

Ellen Oswald - Midcontinent ISO, Inc. - 2

Answer	Yes
Document Name	

Comment

Based on our response to Question 7, there is no need for the Reliability Coordinator to be an applicable entity or involved with the TPL-001-5 standard in any way.

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	Yes
Document Name	

Comment

We believe that consultation between the TP and PC is sufficient for determining known outages to represent in System models.

Likes 0	
Dislikes 0	

Response

Joe McClung - JEA - 1,3,5 - FRCC, Group Name JEA Voters	
Answer	Yes
Document Name	
Comment	
Please see JEA's response under question #7 above. Address FERC's directive under p.40 from O. 786 with a revision of IRO-017 standard.	
Likes 1	JEA, 5, Babik John
Dislikes 0	
Response	

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA does not agree that consultation with the Reliability Coordinator is necessary.	
Likes 0	
Dislikes 0	
Response	

Long Duong - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
SNPD does not have additional comments.	

Likes 0	
Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 3

Answer	Yes
Document Name	

Comment

We do not believe that the RC should be included in the applicability for this standard. As mentioned above, we do not believe that involving the Reliability Coordinator would lead to any fruitful discussions from a planning perspective.

Likes 0	
Dislikes 0	

Response

Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb

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	
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	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Payam Farahbakhsh - Hydro One Networks, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 1	Hydro One Networks, Inc., 3, Malozewski Paul
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
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	
Kevin Giles - Westar Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

James Anderson - CMS Energy - Consumers Energy Company - 1,3,4,5	
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	

Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jeanne Kurzynowski - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1	

Answer	Yes
Document Name	
Comment	
Likes 1	Manitoba Hydro , 5, Xiao Yuguang
Dislikes 0	
Response	
John Seelke - LS Power Transmission, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1,5, Group Name LCRA Compliance	
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	
Fred Frederick - Southern Indiana Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments on this question.	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5	
Answer	
Document Name	
Comment	
Please see comments of Joe O'Brien NIPSCO.	

Likes 0	
Dislikes 0	

Response

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2, Group Name IRC Standards Review Committee

Answer	
Document Name	

Comment

As noted in the SRC's response to Question 7, above, the language of part 1.1.2, as proposed, is unclear as to the degree to which it requires any action of the RC. If the standard is clarified to give the TP/PC sole discretion in selecting the outages, then the RC has no role in this process, and there is no need to worry about whether the RC should be listed among the entities to whom the standard applies.

Note: ISO-NE does not support this comment.

Likes 0	
Dislikes 0	

Response

9. FERC Order No. 786 Paragraphs 40-45 direct modification to address significant planned maintenance outages with durations less than 6 months in planning assessments.   Are you aware of an existing standard/requirement, consistent with industry practice and applicability that requires review and coordination of significant known maintenance outages less than 6 months in duration for inclusion in System models (TPL 001-4 Requirement R1 Part R1.1.2)?

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

Answer	No
Document Name	

Comment

No we are not aware of any other standards/requirements that meet these stipulations. However, to reiterate the response and suggestion from Question 7: reducing the 6 month period to something like “outages spanning the entire season under study” would be reasonable. Limitations that arise due to shorter term outages are an operating horizon issue mitigated by operating practices, not a planning horizon issue.

Likes 0	
Dislikes 0	

Response

Long Duong - Public Utility District No. 1 of Snohomish County - 1

Answer	No
Document Name	

Comment

SNPD is not aware of an existing Standard/Requirement, consistent with industry practice and applicability, that requires review and coordination of significant known maintenance outages less than 6 months in duration for inclusion in system models. This newly suggested Requirement is not practical for PCs and TPs to consider. SNPD obtained initial cases from WECC-approved cases with anticipated topology, system loads and generation. SNPD reviewed and updated these cases based on budget-approved and projected transmission line projects, projected generation resources, and forecasted peak demand data. When a long-term outage (more than 6-12 months) is being planned and needs to be considered for a selected study case, we will update the case to reflect the intended plan for All-Lines-in-Service ("ALIS") N-0 conditions.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	No
Document Name	

Comment

AEP is not aware of any existing obligations that are duplicative of what has been proposed.

Likes 0	
Dislikes 0	
Response	
Joe McClung - JEA - 1,3,5 - FRCC, Group Name JEA Voters	
Answer	No
Document Name	
Comment	
This directive can rightfully be addressed by a revision of IRO-017 Outage Coordination standard. This directive pre-dates IRO-017 and is not relevant anymore to be addressed under the proposed TPL-001-5.	
Likes 1	JEA, 5, Babik John
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	No
Document Name	
Comment	
We are not aware of any existing standard/requirement in the planning horizon which requires review and coordination of significant known maintenance outages less than 6 months. However, these outages are typically addressed in the operations timeframe.	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	No
Document Name	
Comment	

PNMR is not aware of an existing standard/requirement for the review and coordination of significant known maintenance outages **less than 6 months** in duration.

Likes 0	
Dislikes 0	

Response

Lynn Goldstein - PNM Resources - Public Service Company of New Mexico - 1,3

Answer	No
Document Name	

Comment

I support PNM's comments.

Likes 0	
Dislikes 0	

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer	No
Document Name	

Comment

FMPA agrees with JEA’s comments

Likes 0	
Dislikes 0	

Response

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer	No
Document Name	

Comment	
Please see comments submitted by Robert Blackne	
Likes 0	
Dislikes 0	
Response	
Ellen Oswald - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
The TP-002 and TPL-003 had a requirement for planned maintenance flexibility that would have applied to outages less than six (6) months within the planning horizon, but that requirements was not transferred to TPL-001-4 and TPL-001-5.	
Likes 0	
Dislikes 0	
Response	
Gary Trent - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	No
Document Name	
Comment	
TEP believes review of planned maintenance outages are more appropriate in the Operating Horizon than the Planning Horizon. This is covered by IRO-017.	
Likes 0	
Dislikes 0	
Response	
Haley Sousa - Public Utility District No. 1 of Chelan County - 5, Group Name Chelan PUD	
Answer	No
Document Name	
Comment	

No, CHPD is not aware of any other standards/requirements that require review and coordination of significant known maintenance outages less than 6 months in duration for inclusion in System models.

CHPD currently studies shorter term outages in the Operational Planning Assessment (daily study), the Short Range Study, and seasonal studies as outlined in the Peak RC methodologies. Issues due to short term outages are studied and mitigated in the operations horizon, not the planning horizon. Outages that should be included in the planning horizon should be outages with a duration spanning the entire study window but not any shorter as these are addressed in the operations horizon.

The challenge with this requirement is that this supports the system models used in an entity's system assessment. The more outages to be included in this analysis, the more models an entity must use in order to support this requirement. Multiple model maintenance to support multiple outages can quickly become a potentially burdensome issue.

The idea of a "planned maintenance outage" has currently begun to be addressed under the IRO-017 standard.

Outage planning in the operations horizon can and does identify when outages won't work during a particular season due to system constraints. Outage planning can also help identify when multiple unintentionally overlapping outages would lead to system issues. Requiring these sorts of outage planning activities to also be carried out in the transmission planning assessment will increase burden to entities as there may need to be numerous studies run to identify issues and full outage details are not always firm. It is common practice in operations to mitigate these by re-scheduling the outage. This is a much more cost-effective solution than implementing capital projects to support outages which have not been fully planned out into the Planning Horizon.

Likes 0	
Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 3

Answer	No
Document Name	

Comment

Known facility or equipment outages should be included in the data submittals for the MOD-032 model-building process.

Likes 0	
Dislikes 0	

Response

Joyce Gundry - Public Utility District No. 1 of Chelan County - 3

Answer	No
Document Name	

Comment

No, CHPD is not aware of any other standards/requirements that require review and coordination of significant known maintenance outages less than 6 months in duration for inclusion in System models.

CHPD currently studies shorter term outages in the Operational Planning Assessment (daily study), the Short Range Study, and seasonal studies as outlined in the Peak RC methodologies. Issues due to short term outages are studied and mitigated in the operations horizon, not the planning horizon. Outages that should be included in the planning horizon should be outages with a duration spanning the entire study window but not any shorter as these are addressed in the operations horizon.

The challenge with this requirement is that this supports the system models used in an entity's system assessment. The more outages to be included in this analysis, the more models an entity must use in order to support this requirement. Multiple model maintenance to support multiple outages can quickly become a potentially burdensome issue.

The idea of a “planned maintenance outage” has currently begun to be addressed under the IRO-017 standard.

Outage planning in the operations horizon can and does identify when outages won't work during a particular season due to system constraints. Outage planning can also help identify when multiple unintentionally overlapping outages would lead to system issues. Requiring these sorts of outage planning activities to also be carried out in the transmission planning assessment will increase burden to entities as there may need to be numerous studies run to identify issues and full outage details are not always firm. It is common practice in operations to mitigate these by re-scheduling the outage. This is a much more cost-effective solution than implementing capital projects to support outages which have not been fully planned out into the Planning Horizon.

Likes 0	
Dislikes 0	

Response

Janis Weddle - Public Utility District No. 1 of Chelan County - 6

Answer	No
Document Name	

Comment

No, CHPD is not aware of any other standards/requirements that require review and coordination of significant known maintenance outages less than 6 months in duration for inclusion in System models.

CHPD currently studies shorter term outages in the Operational Planning Assessment (daily study), the Short Range Study, and seasonal studies as outlined in the Peak RC methodologies. Issues due to short term outages are studied and mitigated in the operations horizon, not the planning horizon. Outages that should be included in the planning horizon should be outages with a duration spanning the entire study window but not any shorter as these are addressed in the operations horizon.

The challenge with this requirement is that this supports the system models used in an entity's system assessment. The more outages to be included in this analysis, the more models an entity must use in order to support this requirement. Multiple model maintenance to support multiple outages can quickly become a potentially burdensome issue.

The idea of a “planned maintenance outage” has currently begun to be addressed under the IRO-017 standard.

Outage planning in the operations horizon can and does identify when outages won't work during a particular season due to system constraints. Outage planning can also help identify when multiple unintentionally overlapping outages would lead to system issues. Requiring these sorts of outage planning activities to also be carried out in the transmission planning assessment will increase burden to entities as there may need to be numerous studies run

to identify issues and full outage details are not always firm. It is common practice in operations to mitigate these by re-scheduling the outage. This is a much more cost-effective solution than implementing capital projects to support outages which have not been fully planned out into the Planning Horizon.	
Likes 0	
Dislikes 0	
Response	
John Seelke - LS Power Transmission, LLC - 1	
Answer	No
Document Name	
Comment	
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	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts	
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	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - Consumers Energy Company - 1,3,4,5 - RF	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
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	
James Anderson - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 4	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
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	

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Greg Davis - Greg Davis On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Greg Davis	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	No
Document Name	
Comment	

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	
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	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Fred Frederick - Southern Indiana Gas and Electric Co. - 3	
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	
Michael Shaw - Lower Colorado River Authority - 1,5, Group Name LCRA Compliance	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1	
Answer	Yes

Document Name	

Comment
For outages shorter than 6 months, there are other assessments (seasonal, monthly, weekly, day ahead and real time) performed by the Transmission Operators or the RC. These outages are included in operating models or EMS models and not the long term planning models.

Likes 1	Manitoba Hydro , 5, Xiao Yuguang
Dislikes 0	

Response

Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	Yes
Document Name	

Comment
NERC IRO-017 Outage Coordination. If SDT wants to include additional requirments that would tighten up the coordination of significant known maintenance outages less than 6 months in duration for inclusion in System models then NERC IRO-017 should be modified. See response to question 7.

Likes 0	
Dislikes 0	

Response

Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	

Comment
As mentioned above in AZPS's response to Questions 7 and 8, IRO-017-1 R3 and R4, essentially meets the intent of TPL 001-4 Requirement R1 Part R1.1.2. AZPS asserts that, giving due consideration to Requirements R3 and R4 of IRO-017-1, which came after FERC order 786, that Part 1.1.2 is not needed. We would recommend removal of this requirement because R3 and R4 of IRO-017 requires coordination between the PC, TP and RC on outages in the planning assessment and also requires jointly developed solutions. These requirements for coordination and joint solution development associated with outages moots the issue being addressed through the addition of this language. To create an additional obligation for RC, TP and PC coordination would be redundant and would not add value to reliability that would justify the additional expenditure of resources.

Likes 0	
Dislikes 0	

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Reference IRO-017-1 R3 and R4. Also, 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 are changed weekly.	
Likes 0	
Dislikes 0	
Response	
Robert Ganley - Long Island Power Authority - 1	
Answer	Yes
Document Name	
Comment	
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 up to the next 12 months.	
Likes 0	
Dislikes 0	
Response	
Payam Farahbakhsh - Hydro One Networks, Inc. - 1	
Answer	Yes
Document Name	
Comment	
IRO-017-1	
Likes 1	Hydro One Networks, Inc., 3, Malozewski Paul
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion	
Answer	Yes
Document Name	
Comment	
NERC IRO-017 Outage Coordination. If SDT wants to include additional requirments that would tighten up the coordination of significant known maintenance outages less than 6 months in duration for inclusion in System models then NERC IRO-017 should be modified. See response to question 7.	
Likes 0	
Dislikes 0	
Response	

John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson	
Answer	Yes
Document Name	
Comment	
IRO-017 requires review of outages less than 6 months in duration and the purpose of that standard is to ensure that outages are properly coordinated in the Operations Planning time horizon and Near-Term Transmission Planning Horizon.	
Likes 0	
Dislikes 0	
Response	

Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
IRO-017-1	
Likes 0	
Dislikes 0	
Response	

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2, Group Name IRC Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Comments: IRO-017 requires the RC to evaluate outages less than 6 months in duration. **Note: MISO does not support this 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	
The SPP Standards Review Group recommends that the drafting team develop language that will include the Transmission Owners (TOs) and Generation Owners (GOs) to help the modeling process as well as ensuring that those particular entities are included into the applicability section of the standard as well. Also, we recommend the drafting team develop a Requirement that would clearly and definitively explains those entities' responsibilities. However, if the drafting team feels that developing language to include the TO and GO is not the appropriate action, we would also suggest considering IRO-017 as another option to pursue.	
Likes 0	
Dislikes 0	
Response	

Kevin Giles - Westar Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5	
Answer	
Document Name	
Comment	
Please see comments of Joe O'Brien NIPSCO.	
Likes 0	
Dislikes 0	
Response	

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	
Document Name	

Comment	
In NERC Reliability Standard IRO-017-1, PacifiCorp as a TOP and BA, performs the functions in Peak RC's Outage Coordination process. IRO-017-1 addresses the 6 month or less outage duration studies, which underscores why TPL-001-5 should continue to address the 6 month or longer duration studies (see Question 7).	
Likes 0	
Dislikes 0	
Response	

10. Do you agree with the 36 month implementation period to address all Requirements except for Requirement R4, Part 4.2, and Requirement 2, Part 2.7 associated with the modified P5 events further defined in the redline changes to Footnote 13.

Gary Trent - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	No
Document Name	
Comment	
Existing substations that do not meet new requriements should be grandfathered in and allowed to be upgraded when other upgrades/maintenance is being performed. Any new requirements would apply to new substations when they are built.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
Texas RE does not agree that it would take 36 months to implement TPL-001-5. Since the PC and RC are frequently the same entity, setting up coordination with an RC should not take 36 months.	
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 cannot agree with a 36 month implementation period. The ambiguity that exist on what constitutes “redundancy” of a protection system component makes it difficult to determine what an appropriate amount of time would be. As written, the standard will require assessments by entities to check components of all protection systems for redundancy, without defining in a clear manner what that redundancy is or should look like. Depending on additional guidance on what redundancy would be, the amount of time that would be needed to do redundancy identification could increase the amount of time necessary to comply with this standard. Without having that clarity, we cannot agree to the proposed 36 month implementation plan.	

Likes 0	
Dislikes 0	

Response

Robert Ganley - Long Island Power Authority - 1

Answer	No
Document Name	

Comment

Since we have significant concerns with the ambiguity of the proposed P5 event / Footnote 13 (see our comments to question #4 and 6), we feel it is premature to consider a specific implementation plan that involves that event. We cannot agree to a proposed implementation plan for an event that needs clarification.

Likes 0	
Dislikes 0	

Response

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer	No
Document Name	

Comment

Please see comments submitted by Robert Blackne

Likes 0	
Dislikes 0	

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer	No
Document Name	

Comment

FMPA agrees with JEA's comments	
Likes 0	
Dislikes 0	
Response	
Lynn Goldstein - PNM Resources - Public Service Company of New Mexico - 1,3	
Answer	No
Document Name	
Comment	
I support PNM's comments.	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	No
Document Name	
Comment	
No, the 36 month implementation period should be extended for the implementation of any CAP required based on the inclusion of additional planned outages in the Planning Assessment.	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	

For utilities having a larger system, a 48 month implementation plan would be preferable to perform a comprehensive field survey of all single points of failure and establish coordination with protection engineers. It also allows additional time to perform the single points of failure analysis required by the standard.

Likes 0	
Dislikes 0	

Response

Joe McClung - JEA - 1,3,5 - FRCC, Group Name JEA Voters

Answer	No
Document Name	

Comment

Part 4.2.2 and both the subparts 4.2.2.1 and 4.2.2.2 should be deleted from the standard. Any cascading issue under extreme events is already addressed by Part 4.2 – 4.2.1. Please see JEA's comments on question #1 above.

Likes 1	JEA, 5, Babik John
Dislikes 0	

Response

Long Duong - Public Utility District No. 1 of Snohomish County - 1

Answer	No
Document Name	

Comment

It will be difficult to agree with the technical assessment to address all Requirements. So the 36 month implementation will be an onerous to nearly an impossible goal that adds little to reliability value.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

AECI does not agree with the revisions to footnote 13 and cannot support any implementation plan that includes these revisions.

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	
Addressing all Requirements, if any, with the exclusion of sub-requirements 4.2 and 2.7 may require period longer than 36 months.	
Likes 0	
Dislikes 0	
Response	

Janis Weddle - Public Utility District No. 1 of Chelan County - 6	
Answer	No
Document Name	
Comment	
Addressing all new requirements (except 4.2 and 2.7) which would include the new spare equipment strategy for the stability analysis and addressing outages per consultation with the RC, may require a period longer than 36 months. Stability analysis is the most time consuming part of the planning assessment so the additional portion to analyze the spare equipment strategy will take some time to develop. Coordinating outages with the RC will also be very time consuming as there is currently no process in place and the RC will have to correspond with numerous entities regarding numerous outages that have the potential to be in scope.	
Likes 0	
Dislikes 0	
Response	

Joyce Gundry - Public Utility District No. 1 of Chelan County - 3	
Answer	No
Document Name	
Comment	

Addressing all new requirements (except 4.2 and 2.7) which would include the new spare equipment strategy for the stability analysis and addressing outages per consultation with the RC, may require a period longer than 36 months. Stability analysis is the most time consuming part of the planning assessment so the additional portion to analyze the spare equipment strategy will take some time to develop. Coordinating outages with the RC will also be very time consuming as there is currently no process in place and the RC will have to correspond with numerous entities regarding numerous outages that have the potential to be in scope.	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
36 months may not provide enough time to build new or upgrade the appropriate existing facilities considering permiting, property acquisition, construction, and coordination of outages.	
Likes 0	
Dislikes 0	
Response	
Haley Sousa - Public Utility District No. 1 of Chelan County - 5, Group Name Chelan PUD	
Answer	No
Document Name	
Comment	
Addressing all new requirements (except 4.2 and 2.7) which would include the new spare equipment strategy for the stability analysis and addressing outages per consultation with the RC, may require a period longer than 36 months. Stability analysis is the most time consuming part of the planning assessment so the additional portion to analyze the spare equipment strategy will take some time to develop. Coordinating outages with the RC will also be very time consuming as there is currently no process in place and the RC will have to correspond with numerous entities regarding numerous outages that have the potential to be in scope.	
Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
There appears to be errors in the text under “Note Regarding Corrective Action Plans.”	
Likes 0	
Dislikes 0	
Response	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	Yes
Document Name	
Comment	
Agree.	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	

The 36 month implementation plan is reasonable for developing a process with protection engineers to assess single points of failure. The RC process is not necessary.	
Likes 1	Manitoba Hydro , 5, Xiao Yuguang
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
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	
John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson	
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	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Greg Davis On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Greg Davis	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Payam Farahbakhsh - Hydro One Networks, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 1	Hydro One Networks, Inc., 3, Malozewski Paul
Dislikes 0	
Response	
Ellen Oswald - Midcontinent ISO, Inc. - 2	
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	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
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	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Giles - Westar Energy - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey Watkins - Jeffrey Watkins On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Anderson - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jeanne Kurzynowski - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
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	

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
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 Seelke - LS Power Transmission, LLC - 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

Teresa Cantwell - Lower Colorado River Authority - 5

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1,5, Group Name LCRA Compliance	
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	
Fred Frederick - Southern Indiana Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2, Group Name IRC Standards Review Committee	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5	
Answer	
Document Name	
Comment	
Please see comments of Joe O'Brien NIPSCO.	
Likes 0	
Dislikes 0	
Response	

11. Do you agree with the 60 month implementation plan for Requirement 4, Part 4.2 and Requirement 2, Part 2.7 associated with the modified P5 events further defined in the redline changes to Footnote 13.?

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

Mike Smith - Manitoba Hydro - 1

Answer	No
Document Name	

Comment

The additional 24 months to implement any resulting Corrective Action Plans for P5 events may be too short. Requirement 4.2 should only be a study requirement and have 36 months to complete. There should be no requirement to implement a Corrective Action Plan for extreme events.

Likes 1	Manitoba Hydro , 5, Xiao Yuguang
Dislikes 0	

Response

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

Though SRP disagrees with the proposed language of 4.2., SRP has no concerns specifically with the implementation plan.

Likes 0	
Dislikes 0	

Response

Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts	
Answer	No
Document Name	
Comment	
AECI does not agree with the revisions to footnote 13 and cannot support any implementation plan that includes these revisions.	
Likes 0	
Dislikes 0	
Response	
Long Duong - Public Utility District No. 1 of Snohomish County - 1	
Answer	No
Document Name	
Comment	
SNPD disagrees with the proposed Requirements, and therefore disagrees with the 60 month implementation plan.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA is concerned that because the system was not designed for extreme events, the fix could be rather intensive requiring a lot of effort and a lengthy lead time to implement. 60 months may not be long enough. BPA believes the focus should be about reducing the likelihood, not preventing it.	
Likes 0	
Dislikes 0	
Response	
Joe McClung - JEA - 1,3,5 - FRCC, Group Name JEA Voters	

Answer	No
Document Name	

Comment

The new language under Requirement R4, Part 4.2.2 and both the subparts 4.2.2.1 and 4.2.2.2 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 4.2 subpart 4.2.1 already addresses the 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 and seems too aggressive. 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: Part 4.2.2 and both the subparts 4.2.2.1 and 4.2.2.2 under Requirement 4, Part 4.2 is not needed since Requirement R4, Part 4.2 – 4.2.1 already addresses it. Regarding Requirement 2, Part 2.7, an additional industry survey shall be conducted 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 1	JEA, 5, Babik John
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

A 72 month implementation plan would be preferable for the development of Corrective Action Plans under TPL-001-5 to address newly-added studies involving single points of failure on Protection Systems. This would allow additional time for utilities with a larger system and the coordination of outages for implementing Corrective Action Plans.

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	No

Document Name	

Comment
We do not agree with the 60 month implementation plan for projects to address the modified P5 events. These changes will require extensive work in order to make protection systems completely redundant for P5 events, requiring switch houses in some cases. If several switch houses are required, 60 months would not provide adequate time to complete the corrective action plans.

Likes 0	
Dislikes 0	

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer	No
Document Name	

Comment
FMPA agrees with JEA's comments

Likes 0	
Dislikes 0	

Response

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer	No
Document Name	

Comment
Please see comments submitted by Robert Blackne

Likes 0	
Dislikes 0	

Response

Robert Ganley - Long Island Power Authority - 1

Answer	No
Document Name	
Comment	
Since we have significant concerns with the proposed 4.2.2 language and with the ambiguity of the proposed P5 event / Footnote 13 (see our comments to question #1, #2, #4 and 6), we feel it is premature to consider a specific implementation plan that involves that event. We cannot agree to a proposed implementation plan for an event that needs clarification.	
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 Duke Energy response to question 10.	
Likes 0	
Dislikes 0	
Response	
John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson	
Answer	No
Document Name	
Comment	
Five years may not be enough time to gather all of the data necessary and fully evaluate all non-redundant components of a Protection.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No

Document Name	

Comment
Texas RE noticed that Requirement 4, part 4.2 is not called out by name in the implementation plan. The extra 24 months is only mentioned in the General Considerations section and not in the section under Effective Date. It is not clear which requirement the extra 24 months applies to, nor is clear that entities are actually given an extra 24 months as it is not mentioned in the Effective Date section. To clarify these actions need to be done by a certain time, **Texas RE recommends the Effective Date section specify all dates by which all actions need to be completed, organized by requirement number.** In addition, Texas RE suggests that the monitoring and reporting should be aligned with PRC-005-6 attributes moving forward. If this adjustment is made, the only additional step required by entities would be: · Identify protective relays without an alternative that provides comparable Normal Clearing times (13.1). · Identify communication system and dc supply, including monitoring alarming attributes (would already be required for PRC-005-6). · Identify control circuitry (already required for PRC-005-6). · Define contingencies for the failure non-redundant components. There is no reason to believe that these steps could not be accomplished by the effective date of TPL-001-5 and would not need an additional 24 months.

Likes 0	
Dislikes 0	

Response

Gary Trent - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	No
Document Name	

Comment
Existing substations that do not meet new requriements should be grandfathered in and allowed to be upgraded when other upgrades/maintenance is being performed. Any new requirements would apply to new substations when they are built.

Likes 0	
Dislikes 0	

Response

Haley Sousa - Public Utility District No. 1 of Chelan County - 5, Group Name Chelan PUD	
Answer	No
Document Name	
Comment	
CHPD disagrees with the proposed requirements in Part 4.2 and therefore disagrees with the 60 month implementation plan.	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	No
Document Name	
Comment	
Oncor believes the extreme events for Requirement 4, Part 4.2 and Requirement 2, Part 2.7 associated with the modified P5 events should not warrant any timetable for developing a Corrective Action Plan. These events are extremely unlikely and would cost Oncor capital project dollars that could have been spent on much more likely events such as single-phase faults with delayed clearing.	
Likes 0	
Dislikes 0	
Response	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3	
Answer	No
Document Name	
Comment	
CHPD disagrees with the proposed requirements in Part 4.2 and therefore disagrees with the 60 month implementation plan.	
Likes 0	
Dislikes 0	
Response	

Janis Weddle - Public Utility District No. 1 of Chelan County - 6	
Answer	No
Document Name	
Comment	
CHPD disagrees with the proposed requirements in Part 4.2 and therefore disagrees with the 60 month implementation plan.	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
The 60 month implementation plan for Req. 4, Part 4.2 and Req. 2 Part 2.7 is appropriate as a significant amount of protection and control related data will have to be gathered in order to facilitate the abilty to perform the new dynamic scenarios.	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes

Document Name	
Comment	
It will take considerable time to develop the contingency events which would need to be included in both steady-state and transient stability studies, whatever is ultimately decided in this regard.	
Likes 0	
Dislikes 0	
Response	
John Seelke - LS Power Transmission, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Anderson - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey Watkins - Jeffrey Watkins On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lynn Goldstein - PNM Resources - Public Service Company of New Mexico - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 4	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Giles - Westar Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
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	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
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	
Ellen Oswald - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Payam Farahbakhsh - Hydro One Networks, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 1	Hydro One Networks, Inc., 3, Malozewski Paul
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 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	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2, Group Name IRC Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Fred Frederick - Southern Indiana Gas and Electric Co. - 3	
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	
Michael Shaw - Lower Colorado River Authority - 1,5, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 5	
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

Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5

Answer	
Document Name	

Comment

Please see comments of Joe O'Brien NIPSCO.

Likes 0	
Dislikes 0	

Response

Greg Davis - Greg Davis On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Greg Davis

Answer	
Document Name	

Comment

No, GTC does not agree with Requirement 4, Part 4.2 (see GTC's response to question #1) and therefore do not agree with the implementation plan.

Likes 0	
Dislikes 0	

Response

12. In looking at all proposed recommendations from the standard drafting team, are the proposed changes a cost effective approach which meets the FERC directives? (*see* *Cost Effectiveness Background Document*)

Gary Trent - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	No
Document Name	
Comment	
Involving the Reliability Coordinator will extend the time necessary to evaluate planned maintenance outages which will reduce cost effectiveness. Planned outages are currently evaluated in the Operating Horizon so this results in at least doubling the effort to evaluate planned outages. A bullet listing of the FERC directives would have been beneficial for this question so additional time would not have been required to search the FERC Order to determine all the FERC directives.	
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	
Per our response to question 10, depending on what the definition of redundancy actually is, the cost to implement, and become compliant with this standard could be significant. More information as to redundancy is needed.	
Likes 0	
Dislikes 0	
Response	

Greg Davis - Greg Davis On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Greg Davis	
Answer	No
Document Name	
Comment	
No, GTC is concerned that the standard implies CAPs are to be created for extreme events. This would not only be cost ineffective, it would be a heavily burdened standard which would not result in the desired reliability benefits.	

Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
New Part 4.2.2 – The obligation to evaluate the new extreme stability 2e-2h event contingencies, go significantly beyond the Part 4.2.1 obligations for all other extreme events and are not expected to be cost effective. The 2e-2h contingencies are classified as extreme events, but Part 4.2.2 requires actions beyond the Part 4.2.1 obligations for the other extreme events, namely the development of a list of possible actions to prevent Cascading, a timetable for implementation of the possible actions, and annual continued review of the implement status and validity of the possible actions. No justification has been provided to justify the expenditure of significantly more time and resources for the new 2e-2h 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 Dominion	
Answer	No
Document Name	
Comment	
No. See question 7 and 9.	
Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	

Please see comments submitted by Robert Blackne

Likes 0	
Dislikes 0	

Response

Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

SCE agrees that all proposals are the cost-effective approach except one proposal. With respect to SCE's comments for Question 6 regarding Footnote 13d, SCE believes that the intention of the proposed TPL-001-5 to require fully-redundant control circuitry without due consideration of status monitoring combined with periodic independent component testing is duplicative for system reliability and is not the most cost-effective option to address the FERC directive. SCE proposes that the cost-effective solution includes the allowance for excluding control circuitry with montioring from footnote 13 d.

Likes 0	
Dislikes 0	

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	No
Document Name	

Comment

New Part 2.4.3 – This obligation to study P1 events for known outage conditions is expected to be cost effective.

New Part 4.2.1 – This obligation is a relocation of the existing second obligation in Part 4.5 of the TPL-001-4 standard and expected to still be cost effective.

New Part 4.2.2 – The obligation to evaluate the new extreme stability 2e-2h event contingencies, go significantly beyond the Part 4.2.1 obligations for all other extreme events and are not expected to be cost effective. The 2e-2h contingencies are classified as extreme events, but Part 4.2.2 requires actions beyond the Part 4.2.1 obligations for the other extreme events, namely the development of a list of possible actions to prevent Cascading, a timetable for implementation of the possible actions, and annual continued review of the implement status and validity of the possible actions. No justification has been provided to justify the expenditure of significantly more time and resources for the new 2e-2h contingencies.

Footnote 13 4 – The obligation to evaluate single control circuit failures is expected to be cost effective, if our recommendation to replace reference to trip coils is replaced with a reference to control circuit auxiliary relays is implemented. Otherwise, the simulation of trip coil failures is not expected to be cost effective because it will be duplicative of a P4 category event simulation, and therefore, unnecessary

Likes 0	

Dislikes 0	

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer	No
Document Name	

Comment

FMPA follows JEA's comments, and additionally offers comments below in response to Question 14. We offered these comments in the last comment period and are disappointed that they appear to have been ignored.

Likes 0	
Dislikes 0	

Response

sean erickson - Western Area Power Administration - 1

Answer	No
Document Name	

Comment

The obligation to mitigate the new extreme stability 2e-2h event contingencies, goes significantly beyond the Part 4.2.1 obligations for all other extreme events. WAPA does not believe that the cost/benefit will be reasonable because the frequency of these SPF events are so seldom, they do not warrant the cost to eliminate them. No data has been provided to demonstrate that SPFs have been a significant factor in system outages.

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	No
Document Name	

Comment

We do not believe the proposed changes to footnote 13 as well as the addition of a corrective action plan requirement for extreme events are a cost effective approach. Including the control circuitry associated with the protective functions would cause a large financial burden to retrofit existing stations, or construct new switch houses, for those stations which fail criteria. Requiring mitigations or corrective action plans for extreme events, which have a very low probability of occurring, would also have a large financial impact with very little impact on system reliability.

Likes 0	
Dislikes 0	

Response

Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6

Answer	No
Document Name	

Comment

New Part 2.4.3 – This obligation to study P1 events for known outage conditions is expected to be cost effective.

New Part 4.2.1 – This obligation is a relocation of the existing second obligation in Part 4.5 of the TPL-001-4 standard and expected to still be cost effective.

New Part 4.2.2 – The obligation to evaluate the new extreme stability 2e-2h event contingencies, go significantly beyond the Part 4.2.1 obligations for all other extreme events and are not expected to be cost effective. The 2e-2h contingencies are classified as extreme events, but Part 4.2.2 requires actions beyond the Part 4.2.1 obligations for the other extreme events, namely the development of a list of possible actions to prevent Cascading, a timetable for implementation of the possible actions, and annual continued review of the implement status and validity of the possible actions. No justification has been provided to justify the expenditure of significantly more time and resources for the new 2e-2h contingencies.

Footnote 13 4 – The obligation to evaluate single control circuit failures is expected to be cost effective, if our recommendation to replace reference to trip coils is replaced with a reference to control circuit auxiliary relays is implemented. Otherwise, the simulation of trip coil failures is not expected to be cost effective because it will be duplicative of a P4 category event simulation, and therefore, unnecessary.

Likes 0	
Dislikes 0	

Response

Joe McClung - JEA - 1,3,5 - FRCC, Group Name JEA Voters

Answer	No
Document Name	

Comment

Not only some of the proposed recommendations from the SDT are cost-prohibitive, but the added reliability benefit is miniscule as compared to the cost and the aggressive implementation schedule that will be needed to achieve the desired outcome. A more reasonable approach is needed to

address the directives. The suggestions in the above questions go a long way to achive a very good balance between the cost effectiveness and realiability of the power system.	
Likes 1	JEA, 5, Babik John
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	No
Document Name	
Comment	
As identified in AZPS's response to question 7 above, there are redundancies associated with outage coordination that reduce the cost effectiveness of the proposed revision. Having this redundant requirement increases the cost without any attendant reliability benefit.	
Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No
Document Name	
Comment	
These changes will take significant engineering resources to study and determine CAPs and potentially significant capital investment to remedy low probability events. It is unlikely that these proposed changes are cost effective.	
Likes 0	
Dislikes 0	
Response	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	No
Document Name	
Comment	

No. See question 7 and 9.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA feels that it is not economically justifiable to spend money on mitigating low probability extreme events. 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	
Long Duong - Public Utility District No. 1 of Snohomish County - 1	
Answer	No
Document Name	
Comment	
The proposed recommendations to the Standard should meet FERC Directives, however the proposed changes are not cost effective and are somewhat duplicative.	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

SRP is concerned implementation of corrective actions for extreme events could result in significant costs with little increase in reliability.	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
The Cost Effectiveness Background document is the technical rationale. It is doubtful that the proposed changes are cost effective. These changes will take significant engineering resources to study and determine CAPs and potentially significant capital investment to remedy low probability events.	
Likes 1	Manitoba Hydro , 5, Xiao Yuguang
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	
From a reliability standpoint, the proposed recommendations from the SDT may meet the FERC directives. However, it remains to be seen if the recommendations will be cost effective or a burden to a utility as each has its own set of facilities that are responsible for.	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	No
Document Name	
Comment	

Review of outages less than six months is not efficient or beneficial.	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1,5, Group Name LCRA Compliance	
Answer	No
Document Name	
Comment	
Review of outages less than six months is not efficient or beneficial.	
Likes 0	
Dislikes 0	
Response	
Janis Weddle - Public Utility District No. 1 of Chelan County - 6	
Answer	No
Document Name	
Comment	

In particular, the proposed recommendation of the standard drafting team regarding the removal of the 6 month window does not represent a cost effective approach due to the lack of a timeframe. This could open the door to numerous un-coordinated outages whose impacts could be better mitigated through outage coordination in the operational timeframe under the existing IRO-017 requirements.

The new spare equipment strategy for stability analysis against P1 and P2 contingencies does not represent a cost effective implementation either. FERC's language in order 786 paragraph 89 states "However, the Commission will not direct a change and instead directs NERC to consider a similar spare equipment strategy for stability analysis upon the next review cycle of Reliability Standard TPL-001-4". In CHPD's experience, the impacts that the steady state analysis was trying to evaluate were thermal and voltage violation in nature; thus to analyze the loss of equipment that provided this function on the system, such as large power transformers, made sense. However, stability simulations, in our experience, are more strongly impacted by clearing times. Therefore, the spare equipment analysis that is useful for the steady state analysis does not typically modify these clearing times, and thus will not likely yield meaningful results to the degree that it does for the steady state analysis. NERC may consider additional language or guidance regarding the stability application of the new spare equipment strategy to better focus its application to those contingencies where clearing times and as a result, stability could be impacted by the loss of the spare equipment.

Lastly, the proposed changes will add burden to entities and could result in great costs for potentially documenting and implementing mitigation for cascading due to Extreme Events.

Likes 0	

Dislikes 0	
Response	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3	
Answer	No
Document Name	
Comment	

In particular, the proposed recommendation of the standard drafting team regarding the removal of the 6 month window does not represent a cost effective approach due to the lack of a timeframe. This could open the door to numerous un-coordinated outages whose impacts could be better mitigated through outage coordination in the operational timeframe under the existing IRO-017 requirements.

The new spare equipment strategy for stability analysis against P1 and P2 contingencies does not represent a cost effective implementation either. FERC's language in order 786 paragraph 89 states "However, the Commission will not direct a change and instead directs NERC to consider a similar spare equipment strategy for stability analysis upon the next review cycle of Reliability Standard TPL-001-4". In CHPD's experience, the impacts that the steady state analysis was trying to evaluate were thermal and voltage violation in nature; thus to analyze the loss of equipment that provided this function on the system, such as large power transformers, made sense. However, stability simulations, in our experience, are more strongly impacted by clearing times. Therefore, the spare equipment analysis that is useful for the steady state analysis does not typically modify these clearing times, and thus will not likely yield meaningful results to the degree that it does for the steady state analysis. NERC may consider additional language or guidance regarding the stability application of the new spare equipment strategy to better focus its application to those contingencies where clearing times and as a result, stability could be impacted by the loss of the spare equipment.

Lastly, the proposed changes will add burden to entities and could result in great costs for potentially documenting and implementing mitigation for cascading due to Extreme Events.

Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	No
Document Name	
Comment	

New Part 2.4.3 – This obligation to study P1 events for known outage conditions is expected to be cost effective.

New Part 4.2.1 – This obligation is a relocation of the existing second obligation in Part 4.5 of the TPL-001-4 standard and expected to still be cost effective.

New Part 4.2.2 – The obligation to evaluate the new extreme stability 2e-2h event contingencies, go significantly beyond the Part 4.2.1 obligations for all other extreme events and are not expected to be cost effective. The 2e-2h contingencies are classified as extreme events, but Part 4.2.2 requires actions beyond the Part 4.2.1 obligations for the other extreme events, namely the development of a list of possible actions to prevent Cascading, a timetable for implementation of the possible actions, and annual continued review of the implement status and validity of the possible actions. No justification has been provided to justify the expenditure of significantly more time and resources for the new 2e-2h contingencies.

Footnote 13 4 – The obligation to evaluate single control circuit failures is expected to be cost effective, if our recommendation to replace reference to trip coils is replaced with a reference to control circuit auxiliary relays is implemented. Otherwise, the simulation of trip coil failures is not expected to be cost effective because it will be duplicative of a P4 category event simulation, and therefore, unnecessary.

Likes 0	
Dislikes 0	

Response

Haley Sousa - Public Utility District No. 1 of Chelan County - 5, Group Name Chelan PUD

Answer	No
Document Name	

Comment

In particular, the proposed recommendation of the standard drafting team regarding the removal of the 6 month window does not represent a cost effective approach due to the lack of a timeframe. This could open the door to numerous un-coordinated outages whose impacts could be better mitigated through outage coordination in the operational timeframe under the existing IRO-017 requirements.

The new spare equipment strategy for stability analysis against P1 and P2 contingencies does not represent a cost effective implementation either. FERC's language in order 786 paragraph 89 states "However, the Commission will not direct a change and instead directs NERC to consider a similar spare equipment strategy for stability analysis upon the next review cycle of Reliability Standard TPL-001-4". In CHPD's experience, the impacts that the steady state analysis was trying to evaluate were thermal and voltage violation in nature; thus to analyze the loss of equipment that provided this function on the system, such as large power transformers, made sense. However, stability simulations, in our experience, are more strongly impacted by clearing times. Therefore, the spare equipment analysis that is useful for the steady state analysis does not typically modify these clearing times, and thus will not likely yield meaningful results to the degree that it does for the steady state analysis. NERC may consider additional language or guidance regarding the stability application of the new spare equipment strategy to better focus its application to those contingencies where clearing times and as a result, stability could be impacted by the loss of the spare equipment.

Lastly, the proposed changes will add burden to entities and could result in great costs for potentially documenting and implementing mitigation for cascading due to Extreme Events.

Likes 0	
Dislikes 0	

Response

Ellen Oswald - Midcontinent ISO, Inc. - 2

Answer	Yes
Document Name	

Comment

As are the proposed modifications outlined in our comments.	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
FERC has directed that the effects of non-redundant components of a system protection system be evaluated. While not all issues of non-redundant parts of a non-redundant propective system are evaluated, the significant items are to be studied. If cascading occurs, a project should be identified.	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2, Group Name IRC Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Note: MISO does not support this comment.	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
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	
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	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Payam Farahbakhsh - Hydro One Networks, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 1	Hydro One Networks, Inc., 3, Malozewski Paul
Dislikes 0	
Response	

Kevin Giles - Westar Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 4	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Lynn Goldstein - PNM Resources - Public Service Company of New Mexico - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	

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	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
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	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Fred Frederick - Southern Indiana Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments on this question.	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	
Document Name	
Comment	
No comment.	
Likes 0	
Dislikes 0	
Response	
James Anderson - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	
Document Name	
Comment	

No comment.	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5	
Answer	
Document Name	
Comment	
Please see comments of Joe O'Brien NIPSCO.	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - Consumers Energy Company - 1,3,4,5 - RF	
Answer	
Document Name	
Comment	
No comment.	
Likes 0	
Dislikes 0	
Response	

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

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	
We wish to change this to YES. This TPL-001-5 update should coordinate with the proposed changes to FAC-010, FAC-014 and the new FAC-015 standards. Specifically, the requirements in FAC-015 specify what system operating limits should be used in planning assessments. Standard TPL-001 covers all other requirements relating to planning assessments. Having a separate standard defining the limits that should be used in planning studies adds unnecessary complication and potential for confusion, therefore these new FAC-015 requirements should be included within TPL-001-5. The fact that both of these standards are being updated now should be taken advantage of so that there are no reliability gaps.	
Likes 0	
Dislikes 0	
Response	
Long Duong - Public Utility District No. 1 of Snohomish County - 1	
Answer	No
Document Name	
Comment	
SNPD does not have a comment.	
Likes 0	
Dislikes 0	
Response	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	No
Document Name	
Comment	
Not aware of any.	
Likes 0	
Dislikes 0	

Response	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	
Please see comments submitted by Robert Blackne	
Likes 0	
Dislikes 0	
Response	
John Seelke - LS Power Transmission, LLC - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts	
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	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
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	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Anderson - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey Watkins - Jeffrey Watkins On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 4	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Giles - Westar Energy - 1	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
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	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ellen Oswald - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Payam Farahbakhsh - Hydro One Networks, Inc. - 1	
Answer	No
Document Name	
Comment	
Likes 1	Hydro One Networks, Inc., 3, Malozewski Paul
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Greg Davis - Greg Davis On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Greg Davis	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	No
Document Name	
Comment	
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	
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	
Likes 0	
Dislikes 0	
Response	
John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson	
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	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2, Group Name IRC Standards Review Committee	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Fred Frederick - Southern Indiana Gas and Electric Co. - 3	
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	
Michael Shaw - Lower Colorado River Authority - 1,5, Group Name LCRA Compliance	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 5	
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	
Mike Smith - Manitoba Hydro - 1	
Answer	Yes
Document Name	

Comment	
The proposed TPL-001-5 requires implementation of capital projects, which directly conflicts with our provincial regulations. We cannot legally adopt this standard. MH will have to review the final changes in detail to determine what to implement as a MH standard.	
Likes 1	Manitoba Hydro , 5, Xiao Yuguang
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
The language of 4.2.2. can be construed as requiring implementation of of corrective actions which include capital projects and additional infrastructure. Such a requirement would contradict the Energy Poicy Act of 2005, specifically the section below: **Energy Policy Act of 2005** **TITLE XII—ELECTRICITY** **Subtitle A—Reliability Standards** **SEC. 1211. ELECTRIC RELIABILITY STANDARDS** **SEC. 215. ELECTRIC RELIABILITY** ''(2) This section does not authorize the ERO or the Commission to order the construction of additional generation or transmission capacity or to set and enforce compliance with standards for adequacy or safety of electric facilities or services.”	
Likes 0	
Dislikes 0	
Response	
Joe McClung - JEA - 1,3,5 - FRCC, Group Name JEA Voters	
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 PC and TP. This can result in a different scenario for applicable Transmission Facilities for CIP-014-2 as identified by PC and TP (CIP-014-2 – section 4. Applicability – 4.1. Functional Entities – 4.1.1 – 4.1.1.3) in accordance with the proposed TPL-001-5 analyses.	
Likes 1	JEA, 5, Babik John
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
IRO-017 already defines the process for studying outages within the Operational Planning Horizon. This standard sets a difference process for the Planning Horizon creating disconnect between operations and planning.	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	Yes
Document Name	
Comment	
FMPA agree's with JEA's comments	
Likes 0	
Dislikes 0	
Response	

Gary Trent - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Assuming that the maintenance outages should be evaluated in the Operating Horizon as discussed in question #9, this could have conflict with IRO-017.	
Likes 0	
Dislikes 0	
Response	
Haley Sousa - Public Utility District No. 1 of Chelan County - 5, Group Name Chelan PUD	
Answer	Yes
Document Name	
Comment	
As mentioned previously, CHPD is aware of redundancy definitions in the 2009 NERC document “Protection System Reliability – Redundancy of Protection,” as well as some of the redundancy methods and requirements described in PRC-012-2 (for RAS systems), which is subject to future enforcement. These multiple NERC definitions of acceptable types of redundancy will likely cause confusion in industry.	
Likes 0	
Dislikes 0	
Response	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3	
Answer	Yes
Document Name	
Comment	
As mentioned previously, CHPD is aware of redundancy definitions in the 2009 NERC document “Protection System Reliability – Redundancy of Protection,” as well as some of the redundancy methods and requirements described in PRC-012-2 (for RAS systems), which is subject to future enforcement. These multiple NERC definitions of acceptable types of redundancy will likely cause confusion in industry.	
Likes 0	
Dislikes 0	

Response

Janis Weddle - Public Utility District No. 1 of Chelan County - 6	
Answer	Yes
Document Name	
Comment	
As mentioned previously, CHPD is aware of redundancy definitions in the 2009 NERC document “Protection System Reliability – Redundancy of Protection,” as well as some of the redundancy methods and requirements described in PRC-012-2 (for RAS systems), which is subject to future enforcement. These multiple NERC definitions of acceptable types of redundancy will likely cause confusion in the industry.	
Likes 0	
Dislikes 0	
Response	

Lynn Goldstein - PNM Resources - Public Service Company of New Mexico - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jeanne Kurzynowski - Consumers Energy Company - 1,3,4,5 - RF	
Answer	
Document Name	
Comment	
No	
Likes 0	
Dislikes 0	
Response	

Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5	
Answer	
Document Name	
Comment	
Please see comments of Joe O'Brien NIPSCO.	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments on this question.	
Likes 0	
Dislikes 0	
Response	

14. Do you have any other general recommendations/considerations for the drafting team?	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
See MidAmerican Energy's comments.	
Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	
Please see comments submitted by Robert Blackne	
Likes 0	
Dislikes 0	
Response	
Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 4	
Answer	No
Document Name	
Comment	
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.	
Likes 0	
Dislikes 0	
Response	

Long Duong - Public Utility District No. 1 of Snohomish County - 1	
Answer	No
Document Name	
Comment	
SNPD does not have additional comments.	
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	
We wish to change this to YES. *R1.1.2. Known 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..* SCL comments: The requirement does not clarify who selects the outages to be included in the study. Will it be at TP's discretion, or will all the outages proposed by the RC be included in the study(ies)? Also, the language did not specify the duration of the outage as selected in consultation with the RC. SCL's previous recommendation calls for outage that fall within the entire season of the planning horizon under study.	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	No
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Gary Trent - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Greg Davis On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Greg Davis	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
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	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Kevin Giles - Westar Energy - 1	
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	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
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	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2, Group Name IRC Standards Review Committee	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	

We agree that Footnote 13 is an improvement over the previous. However there are still some ambiguities that should be clarified either directly or through appropriate descriptions in the rationale boxes or supplementary material section. We believe ambiguities may lead to confusion during the necessary Protection System assessments, or unnecessary expenditures by entities.

13.b

Please clarify wording on “a single communication system (…) which is not monitored or reported”. Please clarify if the intent is that a “single monitored communication system” means that a single communication channel which is monitored and reported meets the redundancy requirement.

13.c

- Please clarify the term “open circuit” and provide an example (in the supplementary material).

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. Is it the intent of this footnote to capture only the opening of the main protective device (breaker/fuse) after the DC system?

If so, the following wording is offered as suggestion:

“13.c 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 total station DC supply by any immediate downstream protective device.” We believe this wording along with appropriate rationale and an example would help clarify this footnote.

Likes 0	
Dislikes 0	

Response	
John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson	
Answer	Yes
Document Name	
Comment	
MOD-032 should be considered for modification to specifically require protection data, including non-redundant elements, if this standard is approved.	
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. We ask the SDT to identify VSLs for Requirement R8. 2. The Standards Authorization Request associated with this project provides 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 limit deviations 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. We ask the SDT to review these standards and identify reasons why Paragraph 81 criteria do not apply. 3. We thank you for this opportunity to provide these comments.	
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 suggests that objectives outlined in the FERC Directives could be accomplished without the need to revise the standard in this manner. The objectives could be met in the form of a NERC project or initiative requesting that these assessements/studies be done in 10% or 20% intervals over a set period of time, and the data submitted to NERC for its review. We feel that requiring these objectives in a standard, with the ever changing	

configuration of the system, would require that this work as proposed be done every year, which would be extremely burdensome. We recommend that the studies and assessments that will be required would be better suited outside of the NERC standards.

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 Dominion

Answer	Yes
Document Name	

Comment

TPL-001-5 R8 should include distribution to impacted RCs and IRO-017-1 R3 be removed.

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…..”

The definition of “Near-Term Transmission Planning Horizon” needs to be clearly documented in the NERC Glossary of Terms. The current definition of “The transmission planning period that covers Year One through five” is not without ambiguity as the meaning of ‘covering Year One’ is not universally agreed upon.

The definition of “Year One” in the NERC Glossary of Terms is defined as

The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For an assessment started in a given calendar year, Year One includes the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One includes the forecasted peak Load period for either 2012 or 2013.

If a Transmission Planner begins an assessment in January of 2011, Year One would include the peak load for 2012 (August) which is 19-months in the future or for 2013 which is 31-months in the future. If a Transmission Planner begins an assessment in December of 2011, Year One would include the peak load for 2012 (August) which is 8-months in the future or for 2013 which is 20-months in the future.

'Year One' covering a time period of as short as 8-months or as long as 31-months is not clear and will lead to misunderstandings and different interpretations of NERC Requirements. We propose that 'Year One' should be defined as:

The time period of the first twelve months beginning on the date an assessment is started.

The definition of "Near-Term Transmission Planning Horizon" would then be completely clarified if it was defined as:

The transmission planning period that begins with the end of Year One and continues through the next four forecasted peak Load periods.

The definition of "Long-Term Transmission Planning Horizon" would also be completely clarified if I t was defined as:

The transmission planning period that begins with the fifth forecasted peak Load period and continues through the tenth forecasted peak Load period (or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete).

Additionally, all of the time periods (such as "Long-term Planning", "Operations Planning", "Same-day Operations", "Real-time Operations", and "Operations Assessment") described and defined in the NERC document "Time Horizons" (most recently modified in 2014) should be moved into the NERC Glossary of Terms.

Likes 0	
Dislikes 0	

Response

Payam Farahbakhsh - Hydro One Networks, Inc. - 1

Answer	Yes
Document Name	

Comment

We agree that footnote 13 is an improvement over the previous. However there are still some ambiguities that should be clarified either directly or through appropriate descriptions in the rationale boxes or supplementary material section. We believe ambiguities may lead to confusion during the necessary Protection System assessments, or unnecessary expenditures by entities.

13.b

Please clarify wording on “a single communication system (…) which is not monitored or reported”. Please clarify if the intent is that a “single monitored communication system” means that a single communication channel which is monitored and reported meets the redundancy requirement.

13.c

Please clarify the term “open circuit” and provide an example (in the supplementary material).

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. Is it the intent of this footnote to capture only the opening of the main protective device (breaker/fuse) after the DC system?

If so, the following wording is offered as suggestion:

> **“13.c 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 total station DC supply by any immediate downstream protective device.” We believe this wording along with appropriate rationale and an example would help clarify this footnote.**

Likes 1	Hydro One Networks, Inc., 3, Malozewski Paul
Dislikes 0	

Response

Ellen Oswald - Midcontinent ISO, Inc. - 2

Answer	Yes
Document Name	

Comment

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 Subcommittee 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.

Unless the SDT has statistical data that supports the notion that the probability of an instrument transformer failure is much lower than the probability of other failure modes identified in Footnote 13, Footnote 13 should be expanded to include instrument transformers, or at a very minimum, current transformers and voltage transformers with single secondary windings.

Likes 0	
Dislikes 0	

Response

Robert Ganley - Long Island Power Authority - 1

Answer	Yes
Document Name	

Comment

Additional Comment for consideration, related to clarification of the Standard:

Regarding Table 1, if the performance requirements (steady state / stability) are not being met, AND, if Table 1 indicates that non-consequential load loss and interruption of Firm Transmission Service are allowed, is a specific corrective action plan required as per Requirement 2.7 (assuming that non-consequential load loss and/or interruption of Firm Transmission Service would allow for meeting the performance requirements)? This question relates to a scenario where Footnote 12 does not apply. A general recommendation is to clarify within the standard whether or not a specific corrective action plan is required to be documented, as per Requirement 2.7, in the Planning Assessment for this scenario (i.e. performance requirements are not being met and Footnote 12 does not apply).

Additional Comment for consideration, related to Requirement #4 (related to clarification of the Standard):

Requirement 4.1 states that "Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1….." Immediately after 4.1, sub-requirements 4.1.1 through 4.1.3 specify specific system/generator stability performance requirements which are not mentioned in Table 1. Our observation is that Table 1 includes steady state and stability related performance requirements. This apparent placement of performance requirements in more than one location within the Standard document is confusing. Recommendation for consideration is to move sub-requirements 4.1.1 through 4.1.3 to Table 1.

Likes 0	
Dislikes 0	

Response

Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC

Answer	Yes
Document Name	

Comment

Footnote 13 should be modified so that the subsections of the footnote are alphabetical (i.e., a, b, c, and d) and not numerical. Currently, the subsections are numbered, one through four.

SCE provided recommended modifications of footnote 13, subsection d, in response to Question 3 for the comment period ending May 24, 2017. SCE would like to reiterate our feedback from the prior comment period. Please see comments submitted by Deborah Vandeventer.

Likes 0	
Dislikes 0	

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	Yes
Document Name	

Comment

We proposed the following general recommendations.

1. Footnote 13 – For the introductory sentence, we suggest; "If the following components of a Protection System are not redundant, then failure of one component must be evaluated".

2. Footnote 13 – Add text to Footnote 13 to explicitly note in the standard that CTs and VTs used by Protection Systems are not to be considered as applicable to Category 5 events. After the list of the four types of applicable comments, we suggest adding; "Current instrument transformers (CTs) and voltage instrument transformers (VTs) used by the Protection System are not to be considered as applicable Protection System components for P5 category events.

Likes 0	
Dislikes 0	

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken

Simmons, Gainesville Regional Utilities, 1, 3, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	Yes
Document Name	2015-10_TPL-001-5_Unofficial_Comment_Form_FMPA (003).pdf
Comment	
FMPA cannot support the standard revision with the addition of 2.4.3 as it is currently worded. FMPA pointed out in the previous comment period that the language used effectively eliminates the ability to apply engineering judgement to study those events that are expected to produce more significant impacts in the Stability analysis portion of the Planning Assessment. As currently worded, 2.4.3 would required Stability analysis of all P1 events which would result in a tremendous amount of work, but very little benifical insight, since P1 events are typically much less severe from a stability perspective. While comments indicating that proposed methods are "too much work" are not often taken very seriously, due to the fact that R2.4 is in reference to the Stability analysis, the amount of additional work, especially for some larger Planning Coordinators and Transmission Planners, could be completely infeasible to simulate and to thoroughly review results (log files and plots). FMPA believes the intent of the drafting team was to capture stability issues related to "known outages", but has unintentionally gone well beyond that. FMPA supports the drafting team exploring whether IRO-017 is the appropriate standard to address FERC's concerns regarding planned outages, but at a minimum believes 2.4.3 needs to be reworded. FMPA suggests an approach very similar to the language used in 2.4.5 to address this issue (i.e. – "selected P1 events….expected to produce more servere System impacts…").	
Likes 0	
Dislikes 0	
Response	
Lynn Goldstein - PNM Resources - Public Service Company of New Mexico - 1,3	
Answer	Yes
Document Name	
Comment	
I support PNM's comments.	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	

Comment	
PNMR recommends that R8 should be revised to include the impacted Reliability Coordinators. With this revision, PNMR believes that IRO-017-1 R3 could be retired as this standard would accomplish the intended reliability objective and would reduce the administrative burden on PCs and TPs. PNMR further recommends that R4 from IRO-017-1 be added to TPL-001-5 R2.7 since it is requiring the CAP be developed with the RC. In addition, the SDT should consider adding the RC as an applicable entity. With this revision, IRO-017-1 R4 could be retired as this standard would accomplish the intended reliability objective. The intention of R2.4.3, as written, is unclear. Is the intention to require known outages be included in the assessment of System peak and Off-Peak conditions? The requirement should be revised to clearly define what is required to be in compliance.	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	

The definition of "Near-Term Transmission Planning Horizon" needs to be clearly documented in the NERC Glossary of Terms. The current definition of "The transmission planning period that covers Year One through five" is not without ambiguity as the meaning of 'covering Year One' is not universally agreed upon.

The definition of "Year One" in the NERC Glossary of Terms is defined as

The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For an assessment started in a given calendar year, Year One includes the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One includes the forecasted peak Load period for either 2012 or 2013.

If a Transmission Planner begins an assessment in January of 2011, Year One would include the peak load for 2012 (August) which is 19-months in the future or for 2013 which is 31-months in the future. If a Transmission Planner begins an assessment in December of 2011, Year One would include the peak load for 2012 (August) which is 8-months in the future or for 2013 which is 20-months in the future.

'Year One' covering a time period of as short as 8-months or as long as 31-months is not clear and will lead to misunderstandings and different interpretations of NERC Requirements. We propose that 'Year One' should be defined as:

The time period of the first twelve months beginning on the date an assessment is started.

The definition of "Near-Term Transmission Planning Horizon" would then be completely clarified if it was defined as:

The transmission planning period that begins with the end of Year One and continues through the next four forecasted peak Load periods.

The definition of "Long-Term Transmission Planning Horizon" would also be completely clarified if it was defined as:

The transmission planning period that begins with the fifth forecasted peak Load period and continues through the tenth forecasted peak Load period (or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete).

Additionally, all of the time periods (such as "Long-term Planning", "Operations Planning", "Same-day Operations", "Real-time Operations", and "Operations Assessment") described and defined in the NERC document "Time Horizons" (most recently modified in 2014) should be moved into the NERC Glossary of Terms.

Likes 0	
Dislikes 0	

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	

Comment

The current draft of the standard seems to straddle the fence between Planning Events and Extreme Events for the performance requirements of Items 2e – 2h. Thus, we suggest that 2e – 2h be placed in one or the other. Our recommendation is to not require a CAP.

If the intent is to not require a CAP, it should be inserted into the Extreme Events category but with the same performance requirements as all the other Extreme Events (i.e., assessment of determining strategies to manage cascading which don't have to be implemented should not be required).

If the intent is to require a CAP, which we do not recommend, other alternatives include:

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.
    - i. Table 1 note (a) already covers "cascading" not being allowed – maybe eliminating the need for a new R4.6 altogether
    - ii. Clearly shows this as a signitifcant "raising-the-bar" event requiring a CAP
    - iii. 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.

R2.4.5: Need some verbiage to allow for excluding 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 "Analysis, including simulations as detailed in R2.4.5, are required only for scenarios where a stability impact could be possible as a result the unavailable equipment" or something similiar would be appropriate. If clarifying verbiage is not included, the result would be the need to devote countless manhours to perform studies that will provide no reliability value.

Suggest changing "Table 1 – Steady State & Stability Performance Extreme Events" to "Table 2 – Steady State & Stability Performance Extreme Events" as these are two separate tables.

The rationale to include 3 phase faults with the failure a non redundant component of a Protection System is too onerous (Extreme Events Table – stability 2e – 2h). This scenario with a SLG fault is onerous enough

Likes 0	
Dislikes 0	

Response

sean erickson - Western Area Power Administration - 1

Answer	Yes
Document Name	

Comment

We proposed the following general recommendations.

Footnote 13 – For the introductory sentence, we suggest; "If the following components of a Protection System are not redundant, then failure of one component must be evaluated".

Footnote 13 – Add text to Footnote 13 to explicitly note in the standard that CTs and VTs used by Protection Systems are not to be considered as applicable to Category 5 events. After the list of the four types of applicable comments, we suggest adding; "Current instrument transformers (CTs) and voltage instrument transformers (VTs) used by the Protection System are not to be considered as applicable Protection System components for P5 category events.

Likes 0	
Dislikes 0	

Response

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5

Answer	Yes
Document Name	
Comment	

In Footnote 13.3 of Table 1, it would be clearer to state, “A single station dc supply associated…"

Likes 0	
Dislikes 0	
Response	

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins

Answer	Yes
Document Name	
Comment	

NVE has some additional comments regarding stability analysis for an entities spare equipment strategy. NVE would like to see some additional language regarding the selection of selected P1 and P2 category events. Perhaps language similar to what is in R4.4 would help to add some clarifying language as to which P1 and P2 contingencies shoud be studied for the spare equipment analysis.

Extreme events 2e – 2h involves studying 3 phase faults on various elements with a failure of a non-redundant component of a protection system. In the presence of a protection system single point of failure, this fault type may not be the most critical. Since most modern protection systems are designed using a higher lever of redundancy, the extreme events described in 2e – 2h will be most applicable to legacy protection systems. Many of these legacy protection systems use single phase electromechanical or solid state relays. With a three phase fault, failure of a single relay would not impact the ability to detect and clear a fault since the relays on the other phases would detect and intitiate clearing as though no relay failure had occurred. For a line to ground fault with a failed relay on that phase, the fault would need to detected and cleared through other means and result in delayed clearing. For a line to ground fault that develops into a three phase fault and mentioned in the technical rationale document, as soon as the fault developed into a three phase fault, the other relays would detect the fault and then clear as appropriate. A line to ground fault would either have to wait to develop into a three phase fault to be cleared or wait until remote relays detect and clear the fault. It would then appear that the line to ground fault with a failed relay would have a greater impact than a three phase fault with a failed relay. NVE recommends that the extreme event 2e – 2h be modified to line to ground faults or something along the lines of “if the non-redundant protection systems is implemented using single phase or ground relays, the 2e – 2h element faults must also be studied for single line to ground faults with delayed clearing.

Likes 0	
Dislikes 0	
Response	

James Anderson - CMS Energy - Consumers Energy Company - 1,3,4,5

Answer	Yes

Document Name	
Comment	

In Footnote 13.3 of Table 1, it would be clearer to state, “A single station dc supply associated…”

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	Yes
Document Name	

Comment

We believe the drafting team should revisit the economic impacts of the proposed changes, specifically those concerning extreme events.

Likes 0	
Dislikes 0	

Response

Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6

Answer	Yes
Document Name	

Comment

We proposed the following general recommendations.

{C}1. {C}Footnote 13 – For the introductory sentence, we suggest; “If the following components of a Protection System are not redundant, then failure of one component must be evaluated”.

Footnote 13 – Add text to Footnote 13 to explicitly note in the standard that CTs and VTs used by Protection Systems are not to be considered as applicable to Category 5 events. After the list of the four types of applicable comments, we suggest adding; “Current instrument transformers (CTs) and voltage instrument transformers (VTs) used by the Protection System are not to be considered as applicable Protection System components for P5 category events.

Likes 0	
Dislikes 0	

Response	
Joe McClung - JEA - 1,3,5 - FRCC, Group Name JEA Voters	
Answer	Yes
Document Name	
Comment	
We again appreciate all the hardwork and expertise of SDT for this project. 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 SDT is headed in the right direction and with some additional guidance/suggestion from the industry; as received during the prior informal comment opportunity and this formal comment period; the directives from FERC and concerns from the SPCS and the SAMS can be easily achieved with minimal burden to the rate payers/customers of the electric power industry but with significant improvement in the reliability of Bulk Power System.	
Likes 1	JEA, 5, Babik John
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Item 4 of the footnote 13 should be rewritten to clarify what is meant by a single control circuit. As written, it is unclear whether it requires two completely independent circuits or simply two independent elements in one circuit.	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
In Footnote 13.3 of Table 1, it would be clearer to state, “A single station dc supply associated…”	
Likes 0	

Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	

AEP is concerned that this project and the proposed revisions go beyond the SAR in a number of ways. Of greatest concern is the inclusion of Footnote 13b (communication systems) and the inference of a Corrective Action Plan in R 4.2.2 (originally provided as R 4.6 in draft 1 from the informal comment period). Because the SAR's scope and direction did not include these topics, we believe these proposed revisions should be removed.

Likes 0	
Dislikes 0	
Response	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	Yes
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	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
After reviewing R1.1.2, BPA believes that the term “Transmission” needs to be inserted into the term “Near-Term Transmission Planning Horizon” to be consistent with the defined term in the NERC glossary.	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
• Perhaps this is an opportunity to link TPL-001-5 and PRC-023-4 into a single assessment? • The timing of models developed under MOD-032 sometime make it difficult to have an exact “year five” model. R2.1.1 could be more flexible – similar to 2.1.2.	
Likes 1	Manitoba Hydro , 5, Xiao Yuguang
Dislikes 0	
Response	
John Seelke - LS Power Transmission, LLC - 1	
Answer	Yes
Document Name	
Comment	
Requirement R1, Part 1.1.2 in TPL-001-5 has language that is redundant to IRO-017-1, Requirements R3 and R4. • Both address planned outages in the Near-Term Planning Horizon.	

- Both require the Transmission Planner and Planning Coordinator to consult with the Reliability Coordinator regarding the selection of know generation and Transmission outages for the Near-Term Planning Horizon.

LSPT prefers the team's language changes in TPL-004-5 for planned outage modeling as opposed to the current IRO-017-1 requirements.

Redundant requirements in NERC Reliability Standards are unwarranted. In FERC's order (issued March 15, 2012 in RC11-6-000) in response to NERC's "Find, Fix, Track, and Report" proposal stated, in part, the following in Paragraph 81:

"…. some current requirements likely provide little protection for Bulk-Power System reliability or may be redundant. The Commission is interested in obtaining views on whether such requirements could be removed from the Reliability Standards with little effect on reliability and an increase in efficiency of the ERO compliance program. If NERC believes that specific Reliability Standards or specific requirements within certain Standards should be revised or removed, we invite NERC to make specific proposals to the Commission identifying the Standards or requirements and setting forth in detail the technical basis for its belief."

In response to Paragraph 81, NERC filed (and FERC subsequently approved) the retirement of 34 requirements within 19 Reliability Standards – see Order No. 788, RM13-8-000. These changes were approved with a single Standard Authorization Request ("SAR")

LSPT understands that Project 2010-10's SAR limits the drafting team's scope to changes to TPL-001-4. Therefore, LSPT recommends that the drafting team propose a revision to the SAR that would allow the team the flexibility to address any NERC approved standard with requirements that addresses planned maintenance outage modeling in planning assessments when the team addresses Paragraph 40 in Order 786. (Paragraph 40 directs NERC to modify Reliability Standard TPL-001-4 to address the concern that the six-month threshold could exclude planned maintenance outages of significant facilities from future planning assessments.)

This proposed SAR change is an example only. However, a SAR change is needed to allow the team the flexibility to propose the retirement of IRO-017-1 Requirements R3 and R4 concurrent with the approval of TPL-001-5 Requirement R1, Part 1.1.2.

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 feels that an alternative first step should have been in a PRC Standard to address the concerns in reference to Single Point Failure. Furthermore, there could be a potential disconnect between the Transmission Planner and Protection Engineers by placing this only in a Planning Standard. Also, we recommend that the draft team includes the Transmission Owner (TO) and Generator Owner (GO) in the applicability section, along with an additional requirement specifying that the TO and GO should provide pertinent data (e.g., contingency definitions, elements tripped) upon request by the PC in order to assess the impact of Single Point of Failure in their assessments.

Likes 0	
Dislikes 0	
Response	

Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
The proposed changes to the Spare Equipment Strategy paragraph (2.4.5) create an unclear requirement for determining if acceptable performance has been met. The revised language introduces a “more severe System impact” standard of performance. This begs the question, “More severe than what?”	
Likes 0	
Dislikes 0	
Response	

Michael Shaw - Lower Colorado River Authority - 1,5, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	
The proposed changes to the Spare Equipment Strategy paragraph (2.4.5) create an unclear requirement for determining if acceptable performance has been met. The revised language introduces a “more severe System impact” standard of performance. This begs the question, “More severe than what?”	
Likes 0	
Dislikes 0	
Response	

Patricia Robertson - BC Hydro and Power Authority - 1,3,5, Group Name BC Hydro	
Answer	Yes
Document Name	
Comment	
BC Hydro appreciates the efforts of the SDT in revising TPL-001-5 – Transmission System Planning Performance Requirements. BC Hydro votes “No” and wishes to provide the following two comments 1. At present BC Hydro is not aware of the process and criteria of Reliability Co-ordinator in identifying planned outages for the Near - Horizon assessment pursuant to Requirement R2, parts 2.1.3 and 2.4.3. Accordingly, BC Hydro is not in a position to assess the impact of this modification to the standard.	

2. The proposed amendments scope from Single Point of Failure is very wide, which will apply to the entire bulk electric system i.e. 100 kV and above. Our recommendation would have been affirmative if the scope were limited to extra high voltage (360 kV and above), where a single point of protection failure after a fault can trigger a major system disturbance.

Below extra high voltage levels, BC Hydro protection systems are built using principles of good utility protection practices, as described in the ANSI/IEEE standards and guides, to ensure that they have acceptable reliability i.e. clear faults without mis-operating. Our protection systems are largely redundant but still can have a single point of failure, such as where there is a shared breaker trip coil or a single telecom fibre etc. Based on our fifty years of operating experience, there is no known case where a single point of failure in our high voltage protection system precipitated in a major system disturbance event. It is because probability of a single failure (in our redundant high voltage protection system) impacting our system performance is negligible. Yet demonstrating compliance to the proposed amendments will require BC Hydro to redirect our critical resources (financial and people) in identifying single points of failure in our every single high voltage P&C asset, estimate incremental protection clearing time associated that failure, and then demonstrate acceptable system performance during the event. Instead of redirecting our critical resources to demonstrate compliance to this negligible probability event, BC Hydro will receive higher reliability benefits by continuing to invest our resources in upgrading the aging protection systems.

Likes 0	
Dislikes 0	

Response

Janis Weddle - Public Utility District No. 1 of Chelan County - 6

Answer	Yes
Document Name	

Comment

The new version of the standard has included the spare equipment strategy into the stability portion of the assessment. This is unnecessary because this analysis is captured in the normal stability study. For example, a transformer qualifies as equipment with lead time greater than a year. The loss of the transformer is captured in the normal stability contingency analysis. If this analysis resulted in an unacceptable response, the scenario would be investigated to determine a mitigation (like using a spare transformer in its place).

CHPD would also appreciate extra language in R2.7 confirming that the required Corrective Action Plans are also extended to the spare equipment analysis and the maintenance outage requirements. This is CHPD’s understanding, but this is not called out directly in the standard. We would appreciate language in R2.7 supporting NERC’s expectation.

Likes 0	
Dislikes 0	

Response

Fred Frederick - Southern Indiana Gas and Electric Co. - 3

Answer	Yes

Document Name	
Comment	

We feel that more explanation/guidance is needed to address what is and is not included in the "components of a Protection System." The research to determine which of these components is a single point of failure, and what the delayed clearing time would be, is potentially quite expansive. We would like to have a more clear idea of the scope of this work and how the impacts differ from P4 and the existing P5 contingencies.

Likes 0	
Dislikes 0	
Response	

Joyce Gundry - Public Utility District No. 1 of Chelan County - 3

Answer	Yes
Document Name	
Comment	

The new version of the standard has included the spare equipment strategy into the stability portion of the assessment. This is unnecessary because this analysis is captured in the normal stability study. For example, a transformer qualifies as equipment with lead time greater than a year. The loss of the transformer is captured in the normal stability contingency analysis. If this analysis resulted in an unacceptable response, the scenario would be investigated to determine a mitigation (like using a spare transformer in its place).

CHPD would also appreciate extra language in R2.7 confirming that the required Corrective Action Plans are also extended to the spare equipment analysis and the maintenance outage requirements. This is CHPD's understanding, but this is not called out directly in the standard. We would appreciate language in R2.7 supporting NERC's expectation.

Likes 0	
Dislikes 0	
Response	

Lauren Price - American Transmission Company, LLC - 1 - MRO,RF

Answer	Yes
Document Name	
Comment	

We proposed the following general recommendations.

- Footnote 13 – For the introductory sentence, we suggest; "If the following components of a Protection System are not redundant, then failure of one component must be evaluated".
- Footnote 13 – Add text to Footnote 13 to explicitly note in the standard that CTs and VTs used by Protection Systems are not to be considered as applicable to Category 5 events. We suggest to add wording (after the list of the four types of applicable comments) like, "Current instrument

transformers (CTs) and voltage instrument transformers (VTs) used by the Protection System are not be considered as applicable Protection System components for P5 category events.	
Likes 0	
Dislikes 0	
Response	
Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1	
Answer	Yes
Document Name	
Comment	
We feel that more explanation/guidance is needed to address what is and isn't included in the "components of a Protection System." The research to determine which of these components is a single point of failure, and what the delayed clearing time would be, is potentially quite expansive. We would like to have a more clear idea of the scope of this work and how the impacts differ from P4 and the existing P5 contingencies.	
Likes 0	
Dislikes 0	
Response	
Haley Sousa - Public Utility District No. 1 of Chelan County - 5, Group Name Chelan PUD	
Answer	Yes
Document Name	
Comment	
The new version of the standard has included the spare equipment strategy into the stability portion of the assessment. This is unnecessary because this analysis is captured in the normal stability study. For example, a transformer qualifies as equipment with lead time greater than a year. The loss of the transformer is captured in the normal stability contingency analysis. If this analysis resulted in an unacceptable response, the scenario would be investigated to determine a mitigation (like using a spare transformer in its place). CHPD would also appreciate extra language in R2.7 confirming that the required Corrective Action Plans are also extended to the spare equipment analysis and the maintenance outage requirements. This is CHPD's understanding, but this is not called out directly in the standard. We would appreciate language in R2.7 supporting NERC's expectation.	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE understands the Note Regarding Corrective Action Plans, the 84 month timeframe, is 84 months from the effective date of TPL-001-4, which was January 1, 2015. By January 1, 2022, the CAPs should no longer include Non-Consequential Load Loss and curtailment of Firm Transmission Service. Texas RE requests justification for that 84 month time period.

Texas RE recommends changing the name of the table with the extreme events to “Table 2”. It is confusing the Table with the planning events and the table with the extreme events are both named “Table 1” and many of the requirements refer to Table 1 even though they refer to different things.

Texas RE also noticed what appears to be a typo for MOD-032 in R1. There is a hyphen before MOD-032 and the font does not match the rest of the standard.

Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5	
Answer	
Document Name	
Comment	

Please see comments of Joe O'Brien NIPSCO.

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

In section 2.4., SRP recommends the last sentence be adjusted to look more like the last sentence of section 2.2. Instead of: “The following studies are required:” Change to: “Qualifying studies need to include the following conditions:”	
Likes 0	
Dislikes 0	
Response	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	
Document Name	TPL-001-5 Comments_Transmission.docx
Comment	
Likes 0	
Dislikes 0	
Response	

Comments received from Kristine Ward, Seminole Electric Cooperative, Inc.

TPL-001-5 Comments

(1) In reviewing the edits to R1.1.2, SECI is concerned about the vagueness of those outages that must be modeled and whether such consultation will now require the RC to meet with each TP and PC separately within the FRCC on an annual basis.

(2) Given the changes to requirement R1.1.2, we believe there needs to be applicability in the standard to the Reliability Coordinator and not just the PC and TP. Also, since the SDT struck out the duration of six months in R1.1.2, there should be a time-frame around the length of transmission outages given some outages are only for a few hours, some for a day, a week, a month, etc., that may not be covering the year, season, or load level entities are assessing.

(3) In reviewing R1.1.2, the term “Transmission” appears to be need to be inserted into the term “Near-Term ***Transmission*** Planning Horizon” to be consistent with the defined term in the NERC glossary.

(2) Regarding the edits to R1.1.2, what happens if the RC, TP, or PC disagree as to which outages to include in the System models? Is it acceptable to the SDT if procedures are written whereby not all entities are in agreement with which outages to include?

(3) In R2.1.5, the SDT changed “studied” to “assessed”. Can the SDT provide background on what is now expected with the term “assessed” differently than what was performed under the term “studied”?

(4) In R2.4.5, can the SDT elaborate on what is expected in, and how detailed, an entity’s spare equipment strategy should be that is needed for TPL-001-5?

(5) In R2.4.5, the wording “The analysis shall simulate the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment” opens entities up to major compliance interpretation issues as it’s not certain that entities will evaluate ALL conditions that the System is expected to experience in our Planning Assessment, this needs to be further clarified by the SDT.

(6) P5, and footnote 13, was modified to cover non-redundant components of a Protection System. This is a substantial additional burden onto entities. Seminole requests the team to perform a cost effectiveness study concerning these additional edits.