Consideration of Comments

Project Name: 2015-10 Single Points of Failure | TPL-001-5

Comment Period Start Date: 4/25/2017

Comment Period End Date: 5/24/2017

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

All comments submitted can be reviewed in their original format on the project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Director of Standards Development, Steve Noess (via email) or at (404) 446-9691.

Questions

1. Do you agree with the proposed changes to Requirement 1, Part 1.1.2 that move away from the 6 month duration outage to limited known outages selected by the Planning Coordinator (PC)/Transmission Planner (TP) in consultation with their Reliability Coordinators (RCs) for the time horizon of the operations planning horizon through the near term planning horizon?
2. Do you agree with the proposed changes to Requirement 2, Part 2.4.5 which addresses the Federal Energy Regulatory Commission (FERC) order to add the spare equipment with long lead time to the dynamics analysis?
3. Do you agree with the further clarification of relay to components of a Protection System with the additional footnote to clarify P5 and extreme events?
4. Do you agree with the proposed Requirement 4, Part 4.6 additions which require a Corrective Action Plan for this subset of Table 1 extreme events (footnote 13, 2e-2h)?
5. Do you agree with the drafting team's approach which doesn't add additional applicable entities to the applicability of the standard? (e.g. RC, Transmission Operator (TO), Generator Operator (GO), Distribution Provider (DP))
6. Do you agree with the 36 month implementation period to address All Requirements except for Requirement R4, Part 4.6, and Requirement 2, Part 2.7 associated with P5 due to Footnote 13 bullets 2, 3 and 4, as well as the definitions?
7. Do you agree with the 60 month implementation plan for Requirement 4, Part 4.6 and Requirement 2, Part 2.7 associated with P5 due to Footnote 13 bullets 2, 3 and 4?
8. Are you aware of any other governing documents that could be in conflict with the current proposal for this draft of the standard?
9. Do you agree with the teams proposed changes to align the VRF/VSLs for Requirement 4, Part 4.6 with the VRF/VSLs for Requirement 2, Part 2.7?
10. Do you have any other general recommendations / considerations for the drafting team?

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

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

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					John Shaver	Arizona Electric Power Cooperative, Inc.	1	WECC
					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Ginger Mercier	Prairie Power, Inc.	1,3	SERC
					Steve McElhaney	CooperativeEnergy	4,6	SERC
					Shari Heino	Brazos Electric Power Cooperative, Inc.	1,5	Texas RE
					Matthew A. Caves	Western Farmers Electric Cooperative	1,5	SPP RE
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Seattle City Light	Ginette Lacasse	1,3,4,5,6	WECC	Seattle City Light Ballot Body	Pawel Krupa	Seattle City Light	1	WECC
					Hao Li	Seattle City Light	4	WECC
					Bud (Charles) Freeman	Seattle City Light	6	WECC
					Mike Haynes	Seattle City Light	5	WECC
					Michael Watkins	Seattle City Light	1,4	WECC
					Faz Kasraie	Seattle City Light	5	WECC
					John Clark	Seattle City Light	6	WECC
					Tuan Tran	Seattle City Light	3	WECC
					Laurrie Hammack	Seattle City Light	3	WECC
Southern Company - Southern Company Services, Inc.	Katherine Prewitt	1		Southern Company	Scott Moore	Alabama Power Company	3	SERC
					Bill Shultz	Southern Company Generation	5	SERC
					Jennifer Sykes	Southern Company Generation and Energy Marketing	6	SERC
Associated Electric	Mark Riley	1,3,5,6			Mark Riley	Associated Electric Cooperative, Inc.	1	SERC

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Cooperative, Inc.				AECI & Member G&Ts	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

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Mark Ramsey	N.W. Electric Power Cooperative, Inc.	1	SERC
					Kevin White	Northeast Missouri Electric Power Cooperative	1	SERC
					Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	3	SERC
					John Stickley	NW Electric Power Cooperative, Inc.	3	SERC
					Jeff Neas	Sho-Me Power Electric Cooperative	3	SERC
					Peter Dawson	Sho-Me Power Electric Cooperative	1	SERC
Lower Colorado River Authority	Michael Shaw	1,5,6		LCRA Compliance	Teresa Cantwell	LCRA	1	Texas RE
					Dixie Wells	LCRA	5	Texas RE
					Michael Shaw	LCRA	6	Texas RE

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no ISO-NE, NYISO and NextEra	Paul Malozewski	Hydro One.	1	NPCC
					Guy Zito	Northeast Power Coordinating Council	NA - Not Applicable	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Bruce Metruck	New York Power Authority	6	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Sylvain Clermont	Hydro Quebec	1	NPCC
					Si Truc Phan	Hydro Quebec	2	NPCC
					Helen Lainis	IESO	2	NPCC
					Laura Mcleod	NB Power	1	NPCC
					Michael Forte	Con Edison	1	NPCC
					Kelly Silver	Con Edison	3	NPCC
					Peter Yost	Con Edison	4	NPCC
					Brian O'Boyle	Con Edison	5	NPCC
					Michael Schiavone	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC
					David Ramkalawan	Ontario Power Generation Inc.	5	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
Midwest Reliability Organization	Russel Mountjoy	10		MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Chuck Lawrence	American Transmission Company	1	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administratino	1,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Mahmood Safi	Omaha Public Power District	1,3,5,6	MRO
					Brad Parret	Minnesota Power	1,5	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Tom Breene	Wisconsin Public Service	3,5,6	MRO
					Jeremy Volls	Basin Electric Power Coop	1	MRO
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Mike Morrow	Midcontinent Independent System Operator	2	MRO
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					Deborah McEndafffer	Midwest Energy, Inc	NA - Not Applicable	NA - Not Applicable
					Robert Gray	Board of Public Utilities (BPU) Kansas City, Kansas	3	SPP RE
					Rober Hirchak	Cleco	1,3,5,6	SPP RE
					Ellen Watkins	Sunflower Electric Power Corporation	1	SPP RE
					Jim Nail	City of Independence, Power and Light Department	5	SPP RE
					John Allen	City Utilities of Springfield, Missouri	4	SPP RE
					Jonathan Hayes	Southwest Power Pool, Inc	2	SPP RE

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Kevin Giles	Westar Energy	1	SPP RE
					Liam Stringham	Sunflower Electric Power Corporation	1	SPP RE
					Louis Guidry	Cleco	1,3,5,6	SPP RE
					Michelle Corley	Cleco Corporation	3	SPP RE
					Mike Kidwell	Empire District Electric Company	1,3,5	SPP RE
					Steve McGie	Board of Public Utilities (BPU) Kansas City, Kansas	3	SPP RE
					J. Scott Williams	City Utilities of Springfield, Missouri	1,4	SPP RE
					Joe Fultz	Grand River Dam Authority	1	SPP RE
					Thomas Maldonado	Excel Energy	NA - Not Applicable	SPP RE
Santee Cooper	Shawn Abrams	1,3,5,6		Santee Cooper	Tom Abrams	Santee Cooper	1	SERC
					Rene' Free	Santee Cooper	1	SERC
					Weijian Cong	Santee Cooper	1	SERC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Chris Wagner	Santee Cooper	1	SERC
					Anthony Noisette	Santee Cooper	1	SERC
PPL – Louisville Gas and Electric Co.	Shelby Wade	1,3,5,6	RF,SERC	PPL NERC Registered Affiliates	Charlie Freibert	LG&E and KU Energy, LLC	3	SERC
					Brenda Truhe	PPL Electric Utilities Corporation	1	RF
					Dan Wilson	LG&E and KU Energy, LLC	5	SERC
					Linn Oelker	LG&E and KU Energy, LLC	6	SERC

SDT Response to Informal Industry Comments

The SDT appreciates the depth of the industry comments and has sought to address each comment submitted during the review of the proposed TPL-001-5 draft Reliability Standard. The SDT has dissected the industry input for each informal comment period question into common themes and seeks to address each here.

Q1	Do you agree with the proposed changes to Requirement 1, Part 1.1.2 that move away from the 6 month duration outage to limited known outages selected by the Planning Coordinator (PC)/Transmission Planner (TP) in consultation with their Reliability Coordinators (RCs) for the time horizon of the operations planning horizon through the near term planning horizon?

In response to Q1, the industry comments ranged from:

- Concerns with "consultation with Reliability Coordinator" text.
- If the RC is required to participate in TPL-001-5, then the RC should be identified as an applicable entity in the TPL standard.
- Outage coordination is an operational issue, not a planning issue.
- IRO-0017 sufficiently covers outage coordination.
- May create additional or duplicate work.
- Consider reducing the 6-month minimum duration for outages that should be considered.
- Need to strengthen the existing Table 1 - P3 and P6 Planning Events to ensure that all outages are accommodated.

Upon reviewing the industry comments, the SDT noted the following considerations of FERC Order 786:

- Planned maintenance outages less than six months may result in impacts during peak and off-peak periods;
- Planned outages during those times should be considered to allow for a single element to be taken out of service without compromising the ability to meet demand;
- Criticality of elements taken out for maintenance could result in N-1 outage and loss of non-consequential load or impact to reliability;

- Planned outages are not “hypothetical outages” and should not be treated as multiple contingencies in the planning standard (should be addressed in N-0 base case);
- Relying on Category P3 and P6 is not sufficient and does not cover maintenance outages;
- The Near-Term Transmission Planning Horizon requires annual assessments using Year one or year two, and year five, and known planned facility outages of less than six months should be addressed so long as their planned start times and durations may be anticipated as occurring for some period of time during the planning time horizon.

The SDT considered the wide range of industry comments received as well as the NERC System Analysis and Modeling Subcommittee (SAMS) report to the NERC Planning Committee (that was also vetted through the industry) and believes the most cost-effective means to address the intent of the NERC directives in FERC Order 786 is to use IRO -017-1 as the vehicle to assure that all types of known scheduled outages are being reviewed and coordinated to mitigate potential reliability impacts. The NERC SAMS recommended that IRO-017-1 should be used to assure that all types of known scheduled outages are being reviewed and coordinated, as well as used to direct actions that must be taken, to mitigate reliability impact (“FERC Order 786 Directives” - NERC SAMS White Paper, July 2016, pg. 3). As directed by FERC Order 786 (Para 40) and consistent with the NERC SAMS recommendation, the TPL-001-5 Requirement R1.1.2 is modified by removing the six month duration criterion. SAMS also recommended that language be added to R1.1.2 referencing the outage coordination process developed in IRO-017-1 Requirement R1. The drafting team believes that requiring consultation with the Reliability Coordinator when the Planning Coordinator and Transmission Planner maintain System models that represent known outages is consistent with IRO-017-1 Requirement R1, as well as Requirement R4 which requires the Planning Coordinator and Transmission Planner to 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. In this way, IRO-017-1 R1 requires the Reliability Coordinator to identify outages and TPL-001-5 R1.1.2 requires the Planning Coordinator and Transmission Planner to consult with the Reliability Coordinator on which known outages to represent in System models for the Near-Term Planning Horizon (the transmission planning period that covers Year One through five).

The term consultation was used in Requirement R1.1.2 to specify that the Reliability Coordinator does not direct which known outages shall be represented in the System models maintained by the Planning Coordinator and Transmission Planner. Instead, the Planning Coordinator and Transmission Planner consult with the Reliability Coordinator to obtain additional information beyond simply what outages are scheduled in outage coordination systems (e.g. CROW, NERC SDX, etc.). The additional information that the Reliability Coordinator can provide to aid the Planning Coordinator and Transmission Planner when selecting known outages to represent may include: the likelihood of the known outage occurring (e.g., outages are not hypothetical, consistent with FERC Order 786, Paragraph 42), the potential for known outages to be concurrent (e.g., situations when Table 1 Category P3 and P6 events are not sufficient to represent System conditions, consistent with FERC Order 786, Paragraph 44), or expected known outage duration (e.g. situations when outages may extend from the Operations Horizon into the Near-Term Planning Horizon; situations when outages span multiple seasons or peak and off-peak periods, consistent with FERC Order 786, Paragraph 41). It is noted that the term consultation has been used elsewhere in the Reliability Standards (e.g. PRC-023-4, VAR-001-4.1) to indicate that other entities may have valuable information necessary for consideration, but where it may be inappropriate for those entities to direct decision-making.

To address outage coordination the SDT is initiating a SAR to enhance IRO-017 to include known outages in the Near-Term Planning Horizon. The specific language will be developed subsequent to an IRO-017 SAR and SDT. The SAR will include the objective to use the coordination process developed pursuant to IRO-017-1 Requirement R1 to direct how all known scheduled outages are reviewed and the actions that must be taken. The following objectives should be added to IRO-017-1 Requirement R1:

- Describe how the review of known scheduled outages by the RC, PC, TO, and TP will be integrated into the Near Term Assessment of the Planning Horizon required by TPL-001-4, and whether and which of these known scheduled outages will be studied in this Assessment.
- Describe how emerging challenges and the inability to schedule outages will be communicated from the TO and RC to the TP and PC to be addressed in a future Corrective Action Plan pursuant to TPL-001-4.

The TPL SDT believes that modifying R1 in such as way offers win-win collaboration between the Reliability Coordinator and the planning entities. The communication process developed in accordance with IRO-017 to meet the above objectives will provide the opportunity for an RC to forward outages that have been scheduled in the near term planning horizon to the Planning Coordinator for analysis as well as providing the opportunity for the Reliability Coordinator to make the Planning Coordinator aware of other operational issues that may be developing. The Planning Coordinator will gain additional situational awareness from the Reliability Coordinator perspective as well as gaining insight on issues for possible inclusion in the Near-Term Planning Horizon.

Q2	Do you agree with the proposed changes to Requirement 2, Part 2.4.5 which addresses the Federal Energy Regulatory Commission (FERC) order to add the spare equipment with long lead time to the dynamics analysis?

The SDT considered the industry comments regarding Question 2 and maintained the proposed TPL-001-5 language that addresses FERC Order 786 Paragraph 89.

Q3	Do you agree with the further clarification of relay to components of a Protection System with the additional footnote to clarify P5 and extreme events?

The SDT paid considerable attention to the depth of the industry comments received regarding Question 3 and has sought to address general and specific industry comments with the following response. If one theme, more than any other, was communicated by industry it was to desire specificity about the Protection System components that must be redundant. The SDT seeks to make clear that the draft Footnote 13, as well as changes to the P5 and extreme events, do not prescribe any level of redundancy. Instead, the changes proposed by the SDT prescribe that SPF in a limited set of non-redundant Protection System components must be considered when assessing system performance given the P5 and extreme events. The performance requirements of TPL-001-5 remain unchanged; the changes to Footnote 13 are intended to improve assessments of existing or planned System equipment that may harbor risks to reliability.

Industry comment: The expansion of components that must be considered when evaluating redundancy will cause industry to perform many more studies, expand equipment monitoring programs, and install redundant equipment. These actions are unwarranted because of the low probability of failure of these non-redundant components.

SDT rationale: The industry has been aware of concerns about Protection System component single point-of-failure (SPF) and corresponding risks to the BES since as early as the March 30, 2009 NERC Alert. The draft TPL-001-5 language proposed by the SDT is consistent with how other identified risks to reliability are incorporated into the Transmission System Planning standard, including similar assessment of low probability events (e.g., breaker failure). The changes to Footnote 13 do not prescribe any level of redundancy. On the contrary, what the SDT has proposed in TPL-001-5 is to specify which non-redundant components of a Protection System must be considered when assessing whether a failure will lead to Delayed Clearing. The purpose of proper simulation of the Planning and Extreme events of TPL-001-5 Table 1 is to ensure the System meets performance requirements. The SDT intends for the accuracy of those simulations to be enhanced by "raising the bar" on SPF.

Industry comment: The Protection System components included in Footnote 13 are unclear, require additional clarity, and should be more prescriptive.

SDT rationale: The SDT agrees with the industry comments. Upon the first release of the proposed TPL-001-5, the SDT desired to maintain the components considered in Footnote 13 as general as possible, while still adhering to the NERC Glossary of Terms definition of Protection System. However, the SDT acknowledges that more specificity within Footnote 13 will better align with the SPCS/SAMS report titled "Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request" and limit the scope of Protection System components considered for non-redundancy. The proposed revised language is incorporated into the revised proposed TPL-001-5.

Industry comment: The rationale section for the Table 1 P5 event and Footnote 13 should be revised.

SDT rationale: The SDT agrees with the comment and made changes to the rational section, as follows.

Revised Paragraph 1: The revisions to Table 1 Category P5 event require an entity to model a single point of failure of a non-redundant Protection System component that will result in Delayed Fault Clearing. The evaluation shall address all Protection Systems affected by the failed component and the increases (if any) of the total fault clearing time. Footnote 13 provides the attributes of the specific system component failure that the entity shall consider for evaluation.

Revised Paragraph 5: [Footnote 13, Part 1] The drafting team sought to limit the scope of protective relays considered non-redundant components of a Protection System in the following ways:

1. May experience a single point of failure.
2. Respond to electrical quantities. Relays that do not respond to electrical quantities, e.g. sudden pressure, are always used in conjunction with relays that respond to electrical quantities and may offer some redundancy.
3. Are necessary for high-speed or Normal Clearing. Given that typical Protection System designs implement primary protection at the local terminal for Normal Clearing and backup protective relaying locally and remotely for Delayed Clearing, the drafting team did not include backup protective relays or overlapping zonal protection as components of a Protection System specified in footnote 13.

Revised Paragraph 6: [Footnote 13, Part 3] Given the increasing importance of communication-aided Protection Systems (e.g., pilot protection schemes, direct transfer tripping schemes, permissive transfer tripping schemes, etc.), the proper operation of the communication system must be considered when considering potential SPF components of Protection Systems. Although the SAMS/SPCS report noted that a SPF in a communication system posed a lower level of risk, the drafting team augmented the SAMS/SPCS recommendations to include reference to the subset of communication systems that are part of a communication-aided Protection System, necessary where the performance of that

Protection System is required to achieve Transmission System Planning Performance Requirements, enumerated in Table 1 of TPL-001-5. In other words, a communication-aided Protection System that may experience a SPF, causing it to operate improperly or not at all leading to Delayed Clearing, must be considered as part of non-redundancy. The drafting team concluded that the failure of communication-aided Protection Systems may take many forms; however, by alarming and monitoring these systems, the overall risk of impact to the Bulk Electric System is reduced to an acceptable level. Most new Protection Systems deployed in the industry include communication-aided protection with component and communication failure alarms monitored at centralized Control Centers. This alarm monitoring is similar to the requirement associated with station DC supplies. Therefore, this requirement is more applicable to legacy systems that need communication-aided Protection Systems to meet performance requirements of the TPL-001-5 standard.

Industry comment: Are Protection System components that protect non-BES equipment connected to the BES buses included in Footnote 13?

SDT rationale: The TPL-001-5 standard establishes Transmission system planning performance requirements whereby each Transmission Planner and Planning Coordinator prepares an annual Planning Assessment of its portion of the BES. The TPL-001-5 Table 1 prescribes the System performance requirements applicable to Facilities given planning and extreme events. By proposing changes to Footnote 13, the SDT prescribes which non-redundant components of a Protection System must be considered for SPF. The failure of a non-redundant component of a Protection System may lead to Delayed Clearing given a fault located on the BES or on non-BES equipment, and should be appropriately simulated.

Industry comment: Single Protection System components of Footnote 13 should be clarified to mean only those single Protection System components that isolate the fault being studied.

SDT rationale: The SDT disagrees with the need to clarify that non-redundant Protection System components must be associated with clearing the fault. The SDT intention is to ensure failure of a non-redundant Protection System component that leads to Delayed Clearing be properly assessed. A non-redundant Protection System component that does not participate in the Normal Clearing of a fault, cannot cause Delayed Clearing if it fails.

Industry comment: Are Protection System components that protect non-BES equipment connected to the BES buses included in Footnote 13?

SDT rationale: The TPL-001-5 standard establishes Transmission system planning performance requirements whereby each Transmission Planner and Planning Coordinator prepares an annual Planning Assessment of its portion of the BES. The TPL-001-5 Table 1 prescribes the

System performance requirements applicable to Facilities given planning and extreme events. By proposing changes to Footnote 13, the SDT prescribes which non-redundant components of a Protection System must be considered for SPF. The failure of a non-redundant component of a Protection System may lead to Delayed Clearing given a fault located on the BES or on non-BES equipment, and should be appropriately simulated.

Industry comment: Single Protection System components of Footnote 13 should be clarified to mean only those single Protection System components that isolate the fault being studied.

SDT rationale: The SDT disagrees with the need to clarify that non-redundant Protection System components must be associated with clearing the fault. The SDT intention is to ensure failure of a non-redundant Protection System component that leads to Delayed Clearing be properly assessed. A non-redundant Protection System component that does not participate in the Normal Clearing of a fault, cannot cause Delayed Clearing if it fails.

Industry comment: The parenthetical portion of the TPL-001-4 Footnote 13 that specifies which relay types are considered should not be removed in the proposed TPL-001-5 Footnote 13.

SDT rationale: [Footnote 13, Part 1] The SDT disagrees with the comment, primarily because all relay types responding to electrical quantities used for primary protection (Normal Clearing) are included in the TPL-001-4 Footnote 13. In other words, the SDT believes that removing the specific relay types allows the applicable entity to consider whether single protective relays may be non-redundant and, if failed, would lead to Delayed Clearing.

Industry comment: A communication system was not part of the Standards Authorization Request as one of the non-redundant components of a Protection System to consider for inclusion in Footnote 13.

SDT rationale: [Footnote 13, Part 2] Consistent with the direction in the SAR, the SDT considered the recommendations for modifying TPL-001-4 as identified in the SPCS/SAMS report titled "Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request". As part of that consideration, the SDT thoroughly reviewed the methodology as well as the findings of the report, such as "a single point of failure in a communication system poses a lower level of risk". However, the SAMS/SPCS report "only analyzed communication equipment in protection systems where communication-aided protection is needed to satisfy the system performance required in NERC Reliability Standards." The SDT believed that this report assumption necessitated that communications be included in the

potential non-redundant components of a Protection System considered in Footnote 13 for two reasons. First, the system performance required, referred to as Performance Measure in the Order 754 data request, was loss of synchronism and/or negatively damped oscillations. This performance requirement is significantly different than the performance requirements of Planning Events of TPL-001-4 Table 1. Second, the SAMS/SPCS report acknowledged that: "the risk associated with a given protection system is dependent on the protection system design. Depending on the protection system design, a single point of failure may result in a failure of the communication-aided system to initiate a high-speed trip (e.g., a permissive overreaching transfer trip scheme), in which case delayed tripping will occur." The SDT believed that evaluating redundancy of Protection System components is integral to properly assessing system performance for the P5 and applicable extreme events; therefore, without presuming Protection System design, the non-redundant communication system must be included in Footnote 13. Additionally, the SAMS/SPCS report stated that communication systems "are typically monitored and alarmed via SCADA or tested periodically", further mitigating the risk of single point-of-failure. The SDT adapted this SAMS/SPCS finding to limit the communication systems to be considered as part of Footnote 13 to those which are not monitored or not reported.
Industry comment: The reference to single DC supply associated with protective functions in Footnote 13 is not specific enough, e.g. battery health.

SDT rationale: [Footnote 13, Part 3] The SDT intended single DC supply to refer to the entire set of equipment that comprises the DC source supplying power to Protection System components necessary for Normal Clearing. In other words, the SDT sought to specify that, within the entire set of equipment comprising the single DC supply, a failure of a piece of equipment that causes the single DC supply to be unable to source power to the protective functions necessary for Normal Clearing must be considered as part of Footnote 13. Relatedly, the SDT agrees that a typical station battery bank is only one part of the single DC supply. Further, a failure of a station battery may be masked for short time by the AC-sourced station battery charger. However, the SDT did not prescribe specific DC supply design configurations. Instead, the SDT emphasized that the single DC supply must be considered for susceptibility to SPF as part of Footnote 13.

Industry comment: It is unclear whether Footnote 13, Item 4 intends for trip coils to be redundant.

SDT rationale: [Footnote 13, Part 4] The SDT intends for trip coils to be considered as part of non-redundant components of a Protection System that may be SPF. It is clear that, given a failure of a single trip coil without a second (e.g., parallel) trip coil, a fault necessitating the opening of the breaker commanded by the unary trip coil will not occur, leading to Delayed Clearing. The SDT does not intend to prescribe whether redundant trip coils are required; instead the SDT has proposed language that requires that non-redundant DC control circuit components, such as trip coils, be considered as part of Footnote 13. The SDT does note that, in most instances, a fault and a failure of a non-redundant trip coil may lead to breaker failure initiation, resulting in Delayed Clearing.

Industry comment: [Footnote 13, Part 4] DC control circuitry should be allowed similar monitoring provisions as with the other parts of Footnote 13.

SDT rationale: The SDT disagrees with the industry comment. While trip coil monitoring devices are commonly available to give awareness of potential trip coil failure, the SDT believes monitoring trip coil failure or relay trouble indication is insufficient to ensure that a SPF is not present within a single control circuit. Similarly, DC undervoltage relaying or other control circuit continuity monitoring may indicate a problem with part of the DC control circuit, but may not give awareness of SPF risks such as serial tripping devices (ANSI #86 and #94 devices). Therefore, The SDT did not incorporate a monitoring provision into Footnote 13, Part 4 and intends for non-redundant components within the DC control circuitry of a Protection System to be considered as part of Footnote 13.

Q4	Do you agree with the proposed Requirement 4, Part 4.6 additions which require a Corrective Action Plan for this subset of Table 1 extreme events (footnote 13, 2e-2h)?

The SDT recognized that the industry comments received regarding Question 4 were particularly negative. The SDT would like to address the most common comment received: requiring Corrective Action Plans as part of Requirement R4.6 goes beyond the scope of the SAR, was not part of the recommendations from the SPCS/SAMS report titled “Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request”, and/or is not justifiable given the low likelihood of occurrence. With regards to industry commenters, approximately two-thirds of respondents expressed this concern. The SDT acknowledges this comment and appreciates the majority of industry feedback. While it is clear that a SPF for a Protection System component may lead to significantly longer Delayed Clearing and notably worse system response than typically analyzed breaker failure conditions, the industry has indicated that the probability of simultaneous SPF occurrence with a bolted three-phase fault is low. Therefore the SDT has restored the assessment of SPF for a Protection System component with a three-phase fault to language consistent with TPL-001-4 Requirement 4.5.

The SPF for a Protection System component is an important topic that, the SDT believes, may involve risks that are underappreciated. The SDT considered using Corrective Action Plan changes in proposed Requirement 4.6 or a new Table 1 Planning Events Category P8 to emphasize the importance of this issue, but given the industry comments and lack of a FERC directive did not “raise the bar” at this time. The SDT would like to document an important considerations it considered, that the fault conditions and system performance requirement, referred to as Performance Measure, of the Order 754 data request were very similar to those of Extreme Events of TPL-001-4 Table 1, namely three-phase fault application and conditions that can indicate Cascading. The primary conclusive finding of the SPCS/SAMS report was: “analysis of the data demonstrates the existence of a reliability risk associated with single points of failure in protection systems that warrants further action.” Further, the SPCS/SAMS report concluded that: “additional emphasis in planning studies should be placed on assessment of three-phase faults involving protection system single points of failure.” Despite the SPCS/SAMS report stopping short of recommending that a Corrective Action Plan be developed when analysis concludes Cascading is caused by the occurrence of a three-phase fault and a failure of a non-redundant Protection System component extreme event, the SDT considered this recommendation consistent with the SAR. However, lacking FERC directive, the SDT determined that the existing TPL-001-4 Requirement R4.5 to evaluate possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the SPF event was sufficient given the risk to reliability. However, Planning Coordinators and Transmission Planners should be aware of some important analytical considerations:

1. Breaker failure Delayed Clearing times are typically 7-14 cycles. This may be significantly shorter than the Delayed Clearing times experienced given a failure of a non-redundant Protection System component.
2. Cascading is significantly less likely to occur given breaker failure clearing times. However, the Delayed Clearing times experienced for three-phase fault and a failure of a non-redundant Protection System component could induce Cascading.
3. Experience has shown a single line-to-ground fault that remains un-cleared for a prolonged period may migrate into multiple phases. Therefore, while a single line-to-ground fault, that would otherwise be cleared, may rapidly become a three-phase fault before Delayed Clearing resulting from a failure of a non-redundant Protection System component.
4. Once assessed, demonstrating Cascading given the identified risk of a three-phase fault and a failure of a non-redundant Protection System component, the impacts to System reliability warrant mitigating plans, encompassed by a Corrective Action Plan.

Q5	Do you agree with the drafting team's approach which doesn't add additional applicable entities to the applicability of the standard? (e.g. RC, Transmission Operator (TO), Generator Operator (GO), Distribution Provider (DP))

The most prevalent industry comment regarding applicability was tied to maintenance outages considered in the Planning Assessment for the Near-term Planning Horizon. The industry comments indicated that the Reliability Coordinator should be added as a TPL-001-5 applicable entity. The second-most common industry comment was to not change the TPL requirements as proposed, but instrad IRO-017-1 should be modified to keep maintenance outage coordination within one standard, leaving the TPL-001-5 as a planning standard. Other prominent industry comments included: the Generator Owner and Transmission Owner should be added as applicable entities due to changes to "components" of Protection Systems; and, the Transmission Operator should be added, along with the Reliability Coordinator, given the inclusion of maintenance outages.

Given the challenges of requirements that span multiple Reliability Standards and the corresponding applicability concerns, the SDT has initiated the process to revise the existing SAR as well as propose a new SAR to enhance IRO-017 as the vehicle to identify and communicate known outages for the Near-Term Planning Horizon.

Q6	Do you agree with the 36 month implementation period to address All Requirements except for Requirement R4, Part 4.6, and Requirement 2, Part 2.7 associated with P5 due to Footnote 13 bullets 2, 3 and 4, as well as the definitions?

The SDT considered the industry comments regarding Question 6 and maintained the proposed TPL-001-5 implementation plan.

Q7	Do you agree with the 60 month implementation plan for Requirement 4, Part 4.6 and Requirement 2, Part 2.7 associated with P5 due to Footnote 13 bullets 2, 3 and 4?

The SDT considered the industry comments regarding Question 7 and maintained the proposed TPL-001-5 implementation plan.

Q8	Are you aware of any other governing documents that could be in conflict with the current proposal for this draft of the standard?

Given the preponderance of industry comments regarding conflicts between IRO-17-1 and the proposed TPL-001-5, the SDT has initiated the process to revise the SAR, as well as propose a new SAR. Similarly, the SDT has removed the proposed Corrective Action Plan in Requirement R4.6 and maintained the existing TPL-001-4 Requirement R4.5.

The SDT would like to address the specific industry 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 SDT understands that CIP-014 Requirement R4 Part 4.1.1.3 applies to Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies. Depending upon the IROL methodologies defined in FAC-014-2, the proposed TPL-001-5 can result in a different scenario for applicable Transmission Facilities for CIP-014-2. However, the SDT believes there is no conflict between CIP-014-2 and the proposed TIP-001-5.

Q9	Do you agree with the teams proposed changes to align the VRF/VSLs for Requirement 4, Part 4.6 with the VRF/VSLs for Requirement 2, Part 2.7?

The SDT believes that the majority of industry comments regarding Question 9 are resolved with the removal of the Corrective Action Plan in Requirement R4.6.

Q10	Do you have any other general recommendations/considerations for the drafting team?

Given the significant changes that the SDT have made to the proposed TPL-001-5 subsequent to the first informal industry comment period, the SDT believes that it has addressed the industry recommendations with regards to topics covered in the Project 2015-10 SAR submitted in response to Question 10.

The SDT would like to address the specific industry comment: when providing additional clarity/rationale on the subject of redundancy, the drafting team consider referring to a technical paper developed by the System Protection Control Task Force developed in 2008 titled: “Protection System Reliability: Redundancy of Protection System Elements”. The SDT has considered the technical paper developed in 2008. It is noted that the SDT has proposed the draft footnote 13 and changes to P5 such that it does not prescribe redundancy. Instead, the changes proposed by the SDT prescribe that SPF in a limited set of non-redundant Protection System components must be considered when assessing system performance given the P5 and extreme events.

Additionally, the SDT would like to address the specific industry: the proposed implementation plan makes reference to, in certain circumstances, carrying over from TPL-001-4 the 84-month exception (our word) period related to Corrective Action Plans including Non-Consequential Load Loss and curtailment of Firm Transmission Service, which is unclear. The SDT has proposed the 36-month implementation period to provide sufficient time for PCs and TP to update their annual assessment to include the new System models and studies required by the TPL-001-5. The additional 24-month CAP drafting period is to identify appropriate CAP related to SPF. The 84-month exception period related to CAP including Non-Consequential Load Loss and curtailment of Firm Transmission Service in TPL-001-4 was kept in the TPL-001-5 implementation plan so that the 84-months will not get inadvertently truncated.