Do not use this form for submitting comments. Use the electronic form to submit comments on TPL-001-5 – Transmission System Planning Performance Requirements. The electronic form must be submitted by 8 p.m. Eastern, Monday, October 23, 2017.

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

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

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

1. Do you agree 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?

☐ Yes
☐ No

Comments:
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.

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?

☐ Yes
☒ No

Comments:
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 Requirement (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 Requirement (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.

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?

☐ Yes
☒ No

Comments:.
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.

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?

☐ Yes
☒ No

Comments:
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.

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?

☐ Yes
☒ No

Comments:
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.
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.”?

☐ Yes  ☒ No

Comments:
Non-redundant components should not consider a single trip coil. Considering 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.

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).

☐ Yes  ☐ No

Comments:
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.

8. Do you agree with omitting the Reliability Coordinator (RC) from the applicability of the TPL-001-5 standard given that Requirement R1, Part 1.1.2 requires consultation between the TP/PC and the RC to determine which known outages to select for representation in System models?

☐ Yes
☒ No

Comments:

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)?

☒ Yes
☐ No

Comments:
NERC IRO-017 Outage Coordination. If SDT wants to include additional requirements 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.

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.

☐ Yes
☐ No

Comments:

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?

☐ Yes
☐ No

Comments:

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)

☐ Yes
☒ No

Comments:
No. See question 7 and 9.

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

☐ Yes
☐ No

Comments:

14. Do you have any other general recommendations/considerations for the drafting team?
Comments:
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 requirements. Therefore we recommend moving Table 1 Extreme Events Stability elements 2e through 2h from the Extreme Events table to Table 1 Planning Events, under a new Category P8, with the following attributes:

- **Category:** P8 Multiple Contingency
- **Initial Condition:** Normal System
- **Event:** 2e through 2h
- **Fault Type:** 3 phase
- **BES Level:** HV, EHV
- **Interruption of Firm Transmission Service Allowed:** Yes
- **Non-Consequential Load Loss Allowed:** Yes

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

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.