# « *Technical Rationale for TPL-001-5* »

# (Justification technique)

# (version anglaise)

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

# Project 2015-10

## Technical Rationale for TPL-001-05

October 2018

RELIABILITY | ACCOUNTABILITY

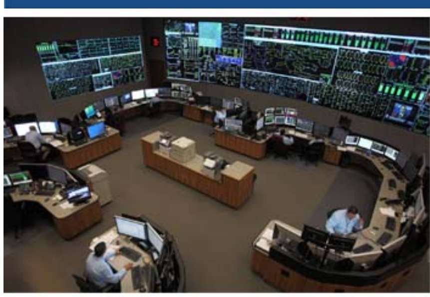

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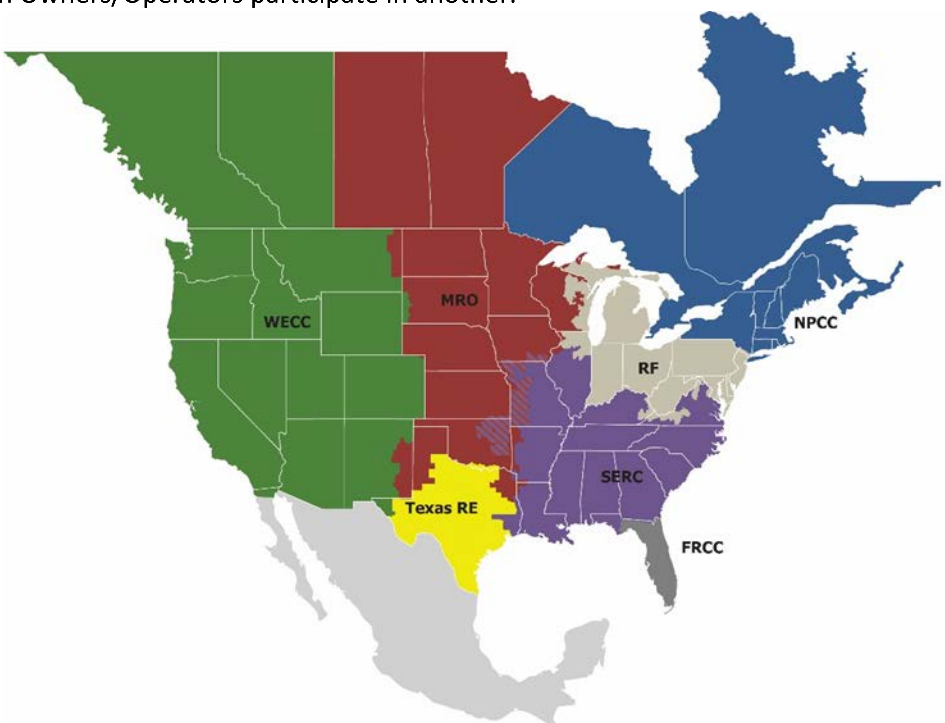
Table of Contents

# Preface

The vision for the Electric Reliability Organization (ERO) Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the seven Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

The North American BPS is divided into seven RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Region while associated Transmission Owners/Operators participate in another.

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|---|---|
| **FRCC** | Florida Reliability Coordinating Council |
| **MRO** | Midwest Reliability Organization |
| **NPCC** | Northeast Power Coordinating Council |
| **RF** | ReliabilityFirst |
| **SERC** | SERC Reliability Corporation |
| **Texas RE** | Texas Reliability Entity |
| **WECC** | Western Electricity Coordinating Council |

# Executive Summary

Project 2015-10 Technical Rationale provides the background and rationale for proposed revisions to Reliability Standard TPL-001-4. The proposed revisions address reliability issues concerning the study of single points of failure (SPF) on Protection Systems from FERC Order No. 754, directives from FERC Order No. 786 regarding planned maintenance outages and stability analysis for spare equipment strategy , and replaces references to the MOD-010 and MOD-012 standards with the MOD-032 Reliability Standard.

## Key Concepts of FERC Order No. 754

The Standard Drafting Team (SDT) took into account the recommendations for modifying NERC Reliability Standard TPL-001-4 identified in both the SPCS and SAMS report titled *Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request* and the *Informational Filing of the North American Electric Reliability Corporation in Response to Order No. 754* to the FERC. In "Table 1 – Steady State and Stability Performance Planning Events," the Category P5 event incorporates Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System. In "Table 1 – Steady State and Stability Performance Extreme Events," breaker failure and failure of a non-redundant component of a Protection System are differentiated. The SDT recognizes that sequence and timing of Protection System action leading to Delayed Fault Clearing may be quite different between the two causalities, and also that fault severity and acceptable consequence of failure of a non-redundant component of a Protection System should be differentiated. Footnote 13 of the "Table 1 – Steady State & Stability Performance Footnotes" describes the non-redundant Protection System components to be considered for Category P5 Planning Events and Stability Extreme Events.

## Key Concepts of FERC Order No. 786

The SDT considered the Commission's concern that the outages of significant facilities less than six months could be overlooked for planning purposes, that Category P3 and P6 do not sufficiently cover planned maintenance outages, and 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. Proposed revisions remove the six month outage duration, shift the consideration of known outages from Requirement R1, which requires what System models shall represent, to Requirement R2, Parts 2.1 and 2.4, which require the study and assessment of known outages. Further, proposed revisions include a requirement to document an outage coordination procedure or the technical rationale for the determination of which known outages to study. Proposed revisions also included the addition of stability assessment for long lead equipment that does not have a spare.

## Summary of proposed revisions

- Requirement R1 – Updated for MOD-032-1 standard.
- Requirement R1, Part 1.1.2 – Removed this requirement.
- Requirement R2, Part 2.1.4 – Added model conditions for steady state analysis of P0 and P1 events for known outages.
- Requirement R2, Part 2.4.4 – Added model conditions for stability analysis of P1 events for known outages.
- Requirement R2, Part 2.4.5 – Added stability analysis requirement for long lead time equipment unavailability.
- Requirement R3, Part 3.2 – Document internal conforming clean-up to incorporate the last sentence of Part 3.5.

- Requirement R4, Part 4.2 – Document internal conforming clean-up to incorporate the last sentence of Part 4.5.
- Table 1 – Modified Category P5 event to include SPF.
- Table 1 – Modified Extreme Events, Stability column to differentiate SPF from stuck breaker.
- Table 1 – Modified Footnote 13 to specify the SPF that should be considered.

# Introduction

NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) is being modified to address reliability issues and standard modification directives contained in FERC Order No. 754[1] and FERC Order No. 786.[2] Proposed Reliability Standard TPL-001-5 revises the TPL-001 standard to address the reliability risks posed by SPF on Protection Systems.

## Background

### FERC Order No. 754

FERC Order No. 754 directed NERC to study the reliability risk associated with SPF in Protection Systems. As a follow-up to a NERC Technical Conference where the risks and concerns associated with SPF were discussed, the NERC System Protection and Control Subcommittee (SPCS) and the System Analysis and Modelling Subcommittee (SAMS) conducted an assessment of Protection System SPF in response to FERC Order No. 754, including analysis of data collected pursuant to a request for data or information under Section 1600 of the NERC Rules of Procedure. The SPCS and SAMS report titled *Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request* and the *Informational filing of the North American Electric Reliability Corporation in Response to Order No. 754* to the FERC provide extensive general discussion about the reliability risks associated with a SPF.

The SDT strongly considered the recommendations of the SPCS and SAMS report, recognizing that the purpose of that report was to determine whether a reliability concern existed demanding NERC to address the study of SPF on Protection Systems. The formation of the Project 2015-10 directly resulted from the SPCS and SAMS report recommendations. However, the SDT's obligation was to consider the reported recommendations and translate them into proposed TPL-001-5 Reliability Standard requirements that are meaningful to Planning Coordinators and Transmission Planners for performance of annual TPL Planning Assessments which adequately account for the reliability risk posed by SPF on Protection Systems.

### FERC Order No. 786

In FERC Order No. 786, FERC directed NERC to address two issues. The first issue is the concern that the six month outage duration threshold could exclude planned maintenance outages of significant facilities from future planning assessments. FERC directed NERC to modify TPL-001-4 to address this concern. The second issue involves adding clarity regarding dynamic assessment of outages of critical long lead time equipment, consistent with the entity's spare equipment strategy. FERC directed NERC to consider this issue upon its next review of TPL-001-4. The NERC SAMS developed a white paper documenting the technical analysis conducted by SAMS to address the two directives contained in the FERC Order No. 786. The white paper provides extensive general discussion regarding the directives.

[1] Order No. 754, *Interpretation of Transmission Planning Reliability Standard*, 136 FERC ¶ 61,186 (2011) ("Order No. 754").

[2] Order No. 786, *Transmission Planning Reliability Standards*, 145 FERC ¶ 61,051 (2013) ("Order No. 786").

# Section 1: Single Points of Failure on Protection Systems (FERC Order No. 754)

## NERC Advisory

On March 30, 2009, NERC issued an advisory[3] report notifying the industry that a SPF issue had caused three significant system disturbances in 5 years.

Transmission Owners, Generation Owners, and Distribution Providers owning Protection Systems installed on the Bulk Electric System (BES) were advised to address SPF on their Protection Systems when identified in routine system evaluations to prevent N-1 transmission system contingencies from evolving into more severe or even extreme events.

These entities were additionally advised to begin preparing an estimate of the resource commitment required to review, re-engineer, and develop a workable outage and construction schedule to address SPF on their Protection Systems.

## FERC Order No. 754

In FERC Order No. 754 Paragraph 20, FERC directed NERC to "to make an informational filing within six months of the date of the issuance of this Final Rule explaining whether there is a further system protection issue that needs to be addressed and, if so, what forum and process should be used to address that issue and what priority it should be accorded relative to other reliability initiatives planned by NERC."

## FERC Technical Conference

A FERC technical conference concerning the Commission's Order 754 titled Staff Meeting on Single Points of Failure on Protection Systems was held on October 24-25, 2011 at FERC in Washington, DC.

At the technical conference, the attendees discussed the SPF issue and narrowed their concerns into four consensus points:

- The concern with assessment of SPF is a performance-based issue, not a full redundancy issue.
- The existing approved standards address assessments of SPF.
- Assessments of SPF of non-redundant primary protection (including backup) systems need to be sufficiently comprehensive.
- Lack of sufficiently comprehensive assessments of non-redundant primary Protection Systems is a reliability concern.

## Joint SPCS-SAMS Report

One outcome of the FERC technical conference was that NERC would conduct a data collection effort to provide a broad factual foundation that could aid in assessing the reliability risks posed by SPF. The NERC Board of Trustees approved the request for data or information under Section 1600 of the NERC Rules of Procedure ("Order No. 754 Data Request") on August 16, 2012.

In September 2015, SPCS and SAMS issued a report to the NERC Planning Committee (PC) and Operating Committee (OC), summarizing the information collected under the Order No. 754 Data Request. The assessment confirmed the existence of a reliability risk associated with SPF in Protection Systems that warrants further action.

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[3] *See Industry Advisory: Single Point of Failure*
*http://www.nerc.com/files/Final_Order_754_Informational_Filing_3-15-12_complete.pdf*

To address this risk, the SPCS and the SAMS considered a variety of alternatives and concluded that the most appropriate recommendation that aligns with FERC Order No. 754 directives and maximizes reliability of Protection System performance is to modify NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) through the NERC standards development process.

The SDT strongly considered the recommendations of the SPCS and SAMS report, as specified by the Project 2015-10 Single Points of Failure Standards Authorization Request (SAR). The SDT recognized that its obligation was to consider the reported recommendations and translate them into proposed TPL-001-5 Reliability Standard requirements that are meaningful to Planning Coordinators and Transmission Planners for performance of annual TPL Planning Assessments. The SPCS and SAMS report recommendations, as well as how they have been addressed in proposed TPL-001-5 by the Project 2015-10 SDT are summarized in the following section.

# Revisions to TPL-001-4

## Single Points of Failure – Category P5 Planning Events

The SPCS and SAMS report states, "Analysis of the data demonstrates the existence of a reliability risk associated with single points of failure in protection systems that warrants further action. The analysis shows that the risk from single point of failure is not an endemic problem and instances of single point of failure exposure are lower on higher voltage systems. However, the risk is sufficient to warrant further action. Risk-based assessment should be used to identify protection systems of concern (i.e., locations on the BES where there is a susceptibility to cascading if a protection system single point of failure exists)".

The modifications to the Category P5 Planning event description are intended to be aligned with the changes to the Table 1, Footnote 13. The SDT has modified Table 1, Footnote 13 to capture the SPCS/SAMS recommendations for Category P5 events, which expands beyond the previously limited set of relays identified in TPL-001-4, to capture the identified SPF of concern. Footnote 13 describes the non-redundant Protection System components to be considered for Category P5 Planning Events, and is discussed further below.

The Table 1 Category P5 event describes a Contingency where a single line-to-ground (SLG) fault occurs and Delayed Fault Clearing results due to the failure of the Protection System, protecting the Faulted element, to operate as designed. Typically, the two most important aspects of the P5 event that affect simulation are the magnitude of SLG fault current and the mode of Protection System failure leading to Delayed Fault Clearing. The latter is especially important and the mode of Protection System failure details make the P5 event unique. The Transmission Planner or Planning Coordinator must be cognizant of the time period during which the Protection System removes Elements from service, as well as the sequence of their removal during isolation of the fault. By definition, Normal Clearing is not expected when a non-redundant component of a Protection System is simulated to have failed; the P5 event implies that the Protection System does not operate as designed to clear the SLG fault in the time normally expected with proper functioning of the installed Protection System. Therefore, when a non-redundant component of a Protection System fails, Delayed Fault Clearing results. This means that correct operation of the backup Protection System occurs with the intentionally designed time delay before fault clearing. Additionally, there may be significant differences in final System configuration due to the Protection System operation to clear the faulted Element. For example, more System Elements may be removed from service when the backup Protection System operates, consistent with Delayed Fault Clearing, than may be expected during primary Protection System operation expected for Normal Clearing. The expected time delays for Protection System operation are critical for proper simulation of the P5 event.

It is anticipated that the most cost-effective Corrective Action Plans to address unacceptable system performance for the P5 Planning Events will likely be to add Protection System component redundancy, consistent with the components to be considered in Footnote 13. Protection System redundancy changes to address Category P5

Event concerns should also reduce or even negate non-redundant components that need to be considered in assessing System performance resulting from simulation of the 2e-2h Extreme Events; hence, potentially mitigating many concerns.

### *Clarification: Why address SPF in TPL-001 and not create a new Reliability Standard for this purpose?*

As part of the recommendations from the SPCS and SAMS report, the option to create a new Reliability Standard to address SPF in the Protection System was considered. Both a new TPL standard for planning-related studies and assessment, as well as a new Protection and Control standard to specify Protection System redundancy were debated by SPCS and SAMS. Ultimately, the recommendation of the SPCS and SAMS report, leading to the formation of the Project 2015-10 SDT, focused upon the simulation and study assessment of the Transmission system given non-redundant components of the Protection System instead of mandating a level of redundancy across a diverse set of equipment and utilities in North America.

It is important to emphasize that modifications to the TPL-001-5 Table 1 Category P5 Planning Event, the TPL-001-5 Table 1 Extreme Stability Events, and related changes to Table 1, Footnote 13 do not establish or mandate a level of redundancy for Protection Systems. Quite the contrary: the modifications presented in TPL-001-5 require planning entities to consider the non-redundant components of Protection Systems that may exist within their respective Systems, to execute appropriate studies, and to assess the impacts that these SPF may have upon the ability to meet Table 1 System performance requirements given Delayed Fault Clearing. TPL-001-5 does not mandate redundancy; TPL-001-5 requires that some non-redundancy components of a Protection System be considered during annual Planning Assessments.

### *Clarification: Why is consideration of fault duration significant for the P5 Planning Event?*

A Protection System is designed to isolate faulted equipment within an expected time duration following fault initiation. When the Protection System does not operate as designed or fails to isolate faulted equipment within the time normally expected with its proper functioning, backup protection capabilities must act to clear the fault. The SDT recognized that Protection Systems used for backup protection are designed with intentional time delays that inherently allows primary protection to actuate first. This is consistent with the Table 1 Planning Event P5 which is characterized by its prescribed Delayed Fault Clearing. The SDT recognized that the sequencing, causality, and mode of failure of a non-redundant component of a Protection System leads to Delayed Fault Clearing by the operation of backup protection, whether local (e.g., breaker failure initiation) or remote (e.g., remote-end terminal tripping consistent with zonal backup protection). The SDT believed the existing defined terms Normal Clearing and Delayed Fault Clearing were appropriate for the revised Table 1 Planning Event P5, as well as the revised Table 1 Footnote 13.

### *Clarification: What is the difference between a top-down versus bottom-up approach to Category P5 Events?*

As part of simulating and analyzing results of P5 Event assessments, two common approaches to the Stability portion of simulations may be appropriate for planning entities to undertake. The first, referred to as the top-down approach, may initially focus upon determining critical clearing times for an entity's System topology given SLG faults. Once critical clearing times are obtained, the planning entity has the opportunity to collaborate with System Protection personnel to assess whether the installed Protection System may achieve the required performance. An advantage of the top-down approach is that the analytical burden to determine critical clearing times is front-loaded upon the planning entity and specific details regarding the Protection System are unnecessary prior to executing dynamics simulations. Conversely, the bottom-up approach may commence by the planning entity requesting the detailed causality and clearing times for SPF on the Protection System from Protection System personnel, requiring an extensive review of installed Protection Systems at the outset. While this approach may delay the execution of P5 Event studies, it may eliminate System topology that is not susceptible to SPF on the Protection System based upon Protection System personnel input and reduces the planning entity's dynamics simulation burden. Whether utilizing a top-down, bottom-up, combination of the two, or any other appropriate approach, the obligation specified in Table 1, Footnote 13 is for the planning entity to consider the non-redundant components of a Protection System that may lead to Delayed Fault Clearing when simulating the P5 Event.

### *Clarification: Is backup protection redundant?*

The majority of BES Protection Systems are designed with overlapping zonal protection, including backup systems which eventually clear a fault in the event of a failure of the Protection System which is designed for Normal Clearing. Backup Protection Systems are not redundant for purposes of TPL-001-5 Table 1, Category P5 Events because they result in Delayed Fault Clearing and/or trip more Elements than the primary Protection System designed for Normal Clearing. Where the Protection System is designed with backup protections, the backup protection clearing time for a SLG fault must be the same as the clearing time for the primary Protection System designed for Normal Clearing, and must trip identical Elements, in order for the backup Protection System to be considered redundant to the primary Protection System. The SDT expects this type of design to be rare in its implementation, and correspondingly, backup protection is not considered redundant.

## Table 1, Footnote 13

Footnote 13 is included in the TPL-001-5 Reliability Standard for the purpose of focusing the Transmission Planner and Planning Coordinator consideration of non-redundant components of a Protection System that may, when they fail, lead to Delayed Fault Clearing of the SLG fault simulated as part of the P5 event.

The SPCS and SAMS report recommended replacing "relay" with "component of a Protection System" in the Table 1 P5 event and replace Footnote 13 in TPL-001-4 with the following alternate wording:

> The components from the definition of 'Protection System' for the purposes of this standard include (1) protective relays that respond to electrical quantities, (2) single station DC supply that is not monitored for both low voltage and open circuit, with alarms centrally monitored (i.e., reported within 24 hours of detecting an abnormal condition to a location where corrective action can be initiated), and (3) DC control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

A factor that the SDT considered when seeking to translate the SPCS and SAMS recommendations into the proposed TPL-001-5 Table 1, Footnote 13 was the need for Planning Coordinators and Transmission Planners to collaborate with System Protection personnel. The SDT recognized that the planning entities do not always have enough information alone to consider Protection System modes of failure or Delayed Fault Clearing than may result. Likewise, the SPCS and SAMS recommendations were adapted to target the potential non-redundant components of a Protection System that may likely need System Protection personnel input when determining how study simulations, performed by the planning entity, should be executed. Based on discussion and industry comment, the SDT revised Footnote 13 to clarify the components of the Protection System that must be considered when simulating Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System. This consideration is intended to account for:

- failed non-redundant components of a Protection System that may impact one or more Protection Systems;
- the duration that faults remain energized until Delayed Fault Clearing, and;

- additional system equipment removed from service following fault clearing depending upon the specific failed non-redundant component of a Protection System.

The SPCS and SAMS report described voltage or current sensing devices as having a lower level of risk of failure to trip due to robustness and likelihood to actually cause tripping upon failure. Therefore, these components of a Protection System are omitted from Footnote 13. Similarly, control circuitry whose failure does not prevent Normal Clearing of a fault, such as reclosing circuitry and reclosing relays, is omitted from Footnote 13 consideration.

### *Clarification: Does Footnote 13 prescribe redundancy?*

It is emphasized that Footnote 13 does not prescribe any level of redundancy; on the contrary, Footnote 13 gives those non-redundant components of a Protection System that shall be considered for simulation of the Table 1 Planning Event P5 and Table 1 Extreme Events Stability column 2e-2h. Further, it is the Table 1 Planning Event P5 which prescribes the required System performance. The consideration of non-redundant components of a Protection System is necessary to properly simulate the Table 1 Planning Event P5 for the purpose of assessing whether required System performance is achieved. If, after proper consideration and simulation, required System performance is achieved, then there may be no impetus to make non-redundant components of a Protection System redundant. On the other hand, after proper consideration and simulation it is demonstrated that required System performance is not achieved, making non-redundant components of a Protection System redundant may be but one of many alternatives for corrective actions to obtain required System performance.

### *Clarification: Why is monitored and reported to a Control Center used in parts of Footnote 13?*

The SDT recognized that some components of a Protection System may be monitored and their integrity reported to a Control Center. Different than an indication of a component failure that may be displayed in a remote site or in a location that may go unnoticed for a period, reporting to a Control Center implies that an unsatisfactory condition would be identified and corrective action be directed in short order. It is noted that short order is consistent with the "within 24 hours of detecting an abnormal condition" recommendation of the SPCS/SAMS report. Given that a risk-based approach to non-redundant components of a Protection System is appropriate, the SDT believed that components that may be SPF but are monitored and reported to a Control Center exhibited lower risk on par with being redundant, and therefore did not warrant P5 Event simulation.

### *Clarification: Why are relays that respond to electrical quantities addressed?*

Noting that Requirement R3, Part 3.3.1 and Requirement R4, Part 4.3.1 require simulation of Protection System action, the SDT sought to limit the scope of Footnote 13a with respect to protective relays that may be non-redundant components of a Protection System. Specifically, Footnote 13 limits single protective relays that may be a SPF to those which respond to electrical quantities and are used for primary protection resulting in Normal Clearing. A SPF in a single protective relay that is a non-redundant component of a Protection System may result in the primary Protection System failing to properly operate, leading to Delayed Fault Clearing performed by backup protective relays and/or overlapping zonal protection. Conversely, the SDT did not include backup protective relays in the scope of Footnote 13a given that a SPF in a single protective relay used for backup protection will not affect primary protection resulting in Normal Clearing.

The SDT recognized that BES Elements are predominantly protected by relays which respond to electrical quantities. However, in some Protection System designs, non-redundant single protective relays which respond to electrical quantities may be redundant to protective relays that do not respond to electrical quantities. For example, an independent differential relay and independent sudden pressure relay may protect the same transformer from faults inside the transformer tank. In this example, the differential relay responds to electrical quantities, while the sudden pressure relay does not. While the transformer differential relay may be a SPF, an internal transformer tank fault may not lead to Delayed Fault Clearing given the sudden pressure protection, provided, in this example, that the resulting clearing time is similar to that achieved with the differential relay. Subsequently, the P5 event, for a single phase-to-ground (line-to-ground) fault in the transformer tank need not be simulated for Delayed Fault Clearing due to the SPF of the transformer differential relay if the resulting clearing time is similar to that achieved with the differential relay. However, care must be taken when evaluating protective relays which respond to electrical quantities in combination with protective relays which do not respond to electrical quantities; in this same example, faults that occurred outside of the transformer tank given the SPF of the non-redundant transformer differential relay would be unaffected by the presence of the sudden pressure relay and would lead to delayed clearing, necessitating its assessment as a P5 event (See Figure 1 and 2).

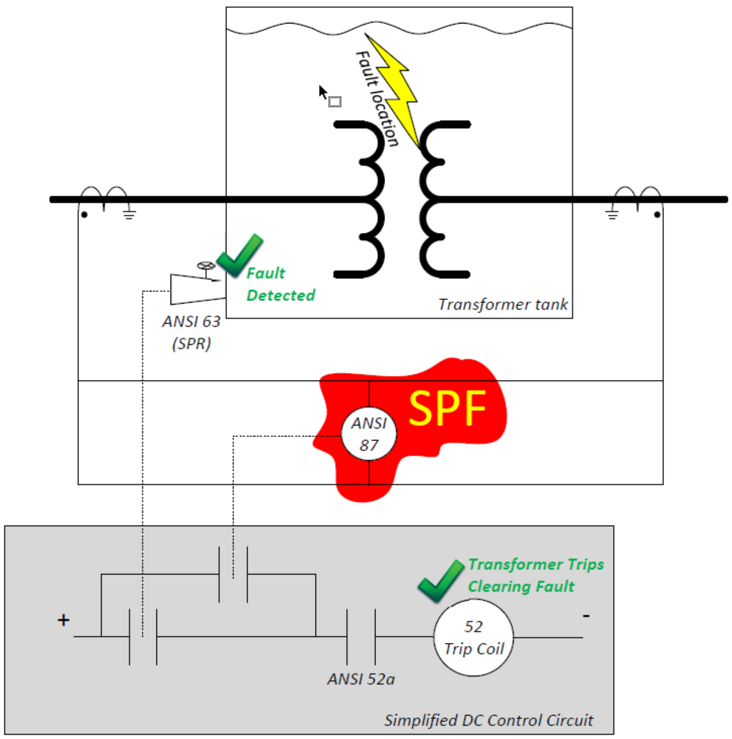


**Figure 1: Internal Transformer Tank Fault with Sudden Pressure Protection and failed Transformer Differential Relay**

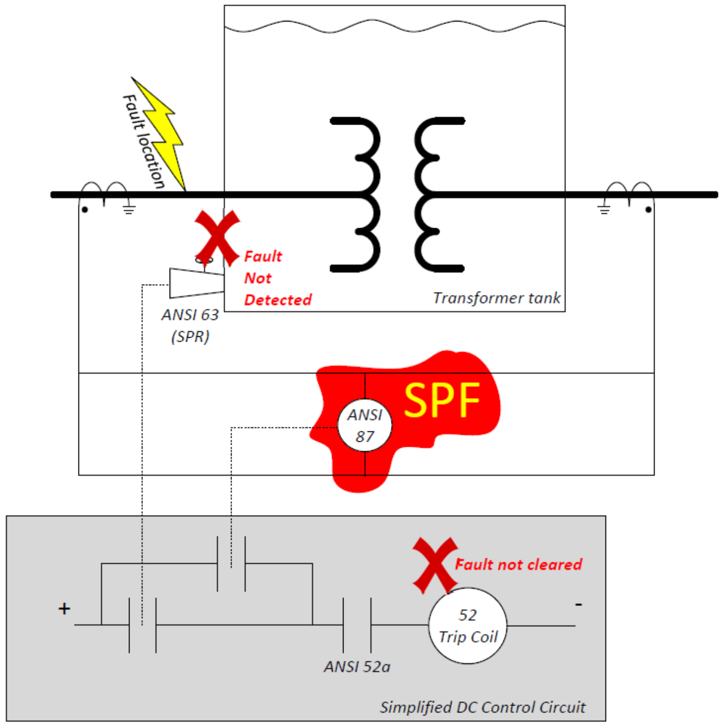


**Figure 2: External Transformer Tank Fault with Sudden Pressure Protection and failed Transformer Differential Relay**

### *Clarification: What is comparable and what is not comparable for purposes of footnote 13?*

The use of "comparable" in Table 1, Footnote 13a applies only to alternatives for a single protective relay that responds to electrical quantities. For an alternative to be comparable to a single protective relay that responds to electrical quantities, the alternative must operate as designed to clear the fault within the time period expected if the single protective relay (that is simulated to fail as a SPF) were to function properly. Clearly, any alternative to a single protective relay that responds to electrical quantities may result in a different Element tripping sequence, leading to a different System topology after fault clearing which must be considered. Therefore, a comparable alternative to a single protective relay that responds to electrical quantities must result in fault clearing within the expected Normal Clearing time period and isolate the fault by tripping similar System Elements.

### *Clarification: Are separate Normal Clearing times comparable?*

The SDT cannot anticipate all Protection System designs. However, the SDT's intent for alternatives to a single protective relay that responds to electrical quantities is implicit in the principle of comparable Normal Clearing times. In some cases, multiple layers of protection may overlap towards achieving a common System protective objective: to provide Normal Clearing. Examination of this design towards the common objective may indicate the Normal Clearing times are comparable. An example of this type of design may be a piloted relay for high-speed fault clearing used in conjunction with a non-piloted relay for primary or fast fault clearing. While these two relays may have different Normal Clearing times, their protective objective is common: to provide Normal Clearing. The clearing times of these two relays may be different, but are likely comparable. The applicable entity must understand the design of their own Protection System for the purpose of considering non-redundant components. Moreover, determination of whether alternatives, which may or may not respond to electrical quantities, provide comparable Normal Clearing times must be made with regard to the Protection System design, the expected fault clearing time, and the protective objective of its proper functioning.

### *Clarification: Why are communication-aided Protection Systems addressed?*

Given the increasing importance of communication-aided Protection Systems (e.g., pilot protection schemes, direct transfer tripping schemes, permissive transfer tripping schemes, line differential relaying schemes, etc.), the proper operation of the communication system must be considered when considering potential SPF components of Protection Systems. The SDT augmented the SPCS/SAMS 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 (TPL) Performance Requirements, enumerated in Table 1 of TPL-001-4. In other words, a communication-aided Protection System that may experience a SPF, causing it to operate improperly or not at all, must be considered as part of non-redundancy. The SDT concluded that, although the failure of communication-aided Protection Systems may take many forms, by monitoring and reporting the status of these systems, the overall risk of impact to the BES can potentially be reduced to an acceptable level. However, monitoring and reporting the status of these systems can only really be considered as a sufficient alternative to physical redundancy if the result is prompt notification and remediation which minimizes the exposure to and consequence of this failed component. Most new Protection Systems deployed in the industry include communication-aided protection with component and communication failure alarms monitored at centralized Control Centers. Therefore, this requirement is more applicable to legacy systems that need communication-aided Protection Systems to meet performance requirements of the TPL standards.

### *Clarification: Why are DC supplies addressed?*

The SDT adopted the fundamental principles of the SPCS/SAMS recommendations regarding station Protection System DC supply. Failure of a single station Protection System DC supply is a significant point of failure as it will prevent the operation of all local protection, including back-up protection. The SDT partly modified the SPCS/SAMS recommendation regarding single station DC supply, including removal of the specific requirement that reporting the detection of an abnormal condition to a location where corrective action can be initiated must occur within 24 hrs. This modification recognizes the wide variety of reporting and monitoring that exists. However, it remains the intention of Footnote 13c, that monitoring and reporting the status of the DC supply can only really be considered as a sufficient alternative to physical redundancy if the result is prompt notification and remediation which minimizes the exposure to and consequence of DC supply failure. Similar to as noted with communication-aided Protection Systems, most new Protection Systems include DC supply status alarms which are monitored at centralized Control Centers; however, they may not necessarily be monitored for both low voltage and open circuit. Therefore, this requirement may be more applicable to legacy systems.

### *Clarification: What differentiates a single station DC supply (Footnote 13c) from a single control circuitry (Footnote 13d)?*

The station DC supply includes station battery, battery chargers and non-battery-based dc supply, as enumerated in the NERC Glossary of Terms definition of Protection System. The control circuitry includes everything from where the station DC supply terminates through and including the trip coils, including the wiring, as well as auxiliary and lockout relays. Further, the NERC Technical Paper *"Protection System Reliability Redundancy of Protection System Elements"* (November 2008) shows a demarcation between DC supply and the remainder of DC control circuitry. The SAMS and SPCS report and recommendations align with Figure 5-12 from this technical paper, shown below as Figure 3.

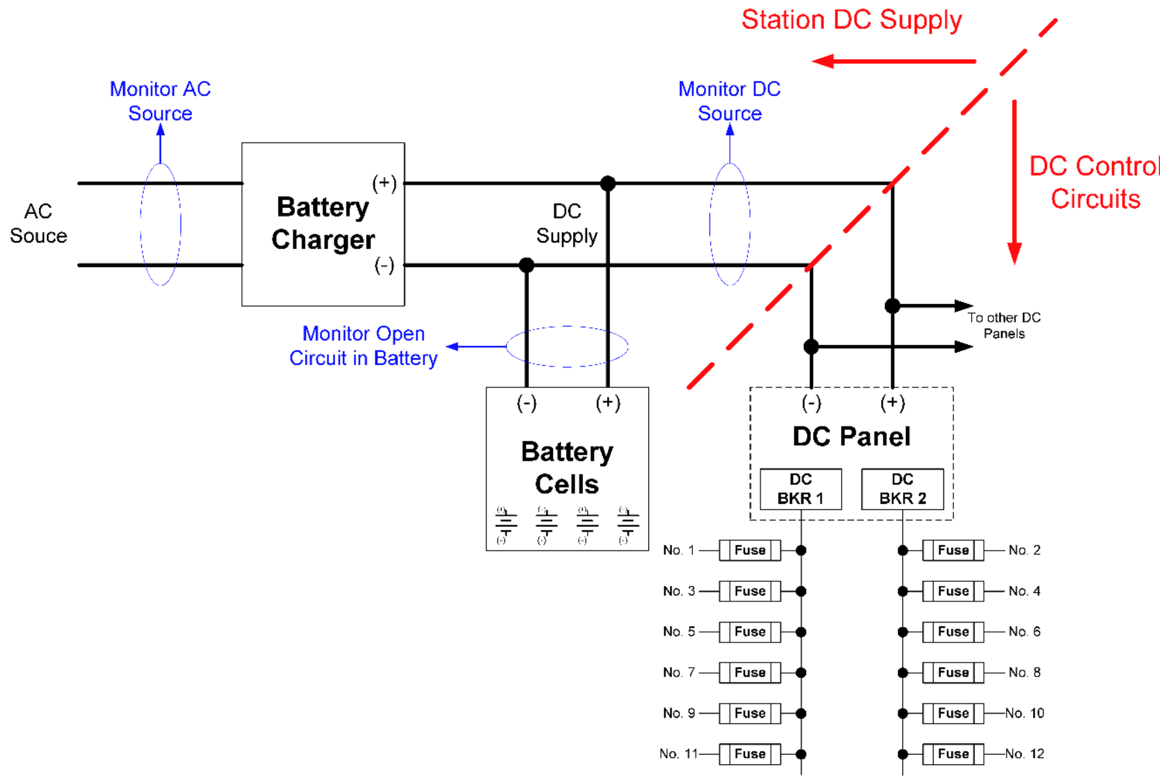


**Figure 3 – Station DC supply and monitoring (Figure 5-2, from NERC Technical Paper "Protection System Reliability Redundancy of Protection System Elements", Nov 2008)**

Simply monitoring for low voltage on the DC supply may omit situations where the DC supply voltage is satisfactory but the source path to DC control circuits may be open circuited. Thus, monitoring for low voltage and open circuit of the DC supply should be considered. Additionally, while the wiring in both the DC supply and the DC circuit have lower probabilities of failure as compared to other Protection System components, the SPCS and SAMS report identified this as a SPF risk.

### *Clarification: Is a battery charging system appropriate redundancy for the battery?*

Battery chargers may not be of sufficient power to source current necessary to operate one or more breakers. For example, it is unlikely that a battery charger without a station battery in parallel would be capable of opening several breakers when demanded by a bus differential Protection System operation. Therefore, a battery charger cannot take the place of a redundant battery DC supply.

### *Clarification: Why is control circuitry addressed?*

The SDT adopted the fundamental principles of the SPCS/SAMS recommendations regarding Protection System DC control circuitry. Failure of a Protection System single control circuitry is a significant point of failure as it will prevent proper tripping and, depending upon its design and mode of failure, may also prevent the initiation of breaker failure protection. Breaker failure is addressed by the Table 1 Planning Event P4 and is discussed in the next section. Further, most, if not all, constituent parts of the control circuitry are generally unmonitored, may fail, and may remain undetected until periodic testing is conducted. This is particularly significant for non-redundant auxiliary relays or lockout relays within the control circuitry because they may be used for multiple functions, such as multiplexing trip signals for differential or breaker failure initiation. Single control circuitry should be considered a non-redundant component of a Protection System given that Delayed Fault Clearing, including significantly delayed remote end or backup clearing, is expected when the non-redundant auxiliary or lockout relay device within the single control circuitry fails.

The single control circuitry is demarcated from the DC supply through and including the trip coil(s) for the purpose of including all devices in the control circuitry which, if failed, may prevent proper Protection System action leading to Delayed Fault Clearing. Trip coils are commonly employed in pairs (dual) for the purpose of incorporating redundancy to actuate the tripping of a circuit breaker or other interrupting device. However, the SDT partly modified the SPCS/SAMS recommendation regarding single control circuitry recognizing that some Protection System designs include a single trip instead of dual trip coils. When a single trip coil is employed, monitoring and reporting the status of the single trip coil can be considered as a sufficient alternative to its physical redundancy given that prompt notification and remediation is expected which minimizes the risk the trip coil failure. However, the trip coil(s), whether implemented singly or in pairs, are only part of the single control circuit; all its constituent parts should be included when considering whether the single control circuit may be a non-redundant component of a Protection System.

## The Distinction between Category P4 and Category P5 Planning Events

"Table 1 – Steady State and Stability Performance Planning Events," makes a clear distinction between breaker failure, Category P4 Planning Events, and failure of a non-redundant component of a Protection System, Category P5 Planning Events. The sequence and timing of Protection System action leading to Delayed Fault Clearing may be quite different between the two fundamentally different causalities. Category P4 events involving the failure specifically of a circuit breaker assume that only the circuit breaker has failed, and that all other protection functions, including proper initiation of local breaker failure operation, has occurred correctly. For Category P5 Planning Events, failure of the various non-redundant components of a Protection System, as enumerated in Table 1, Footnote 13, can result in a relatively broader range of final system states, resulting from the Delayed Fault Clearing associated with the specific SPF, and which may or may not resemble the system states resulting from Delayed Fault Clearing associated with circuit breaker failure. Likewise, the Delayed Fault Clearing time that results from a Category P5 Event may be significantly longer that that expected when simulating Category P4 Event.

It is noted that there may be many instances where a fault followed by a breaker failure results in the exact same study simulations as a fault followed by a failure of a non-redundant component of a Protection System. There could be slight differences in clearing times and the Planning Coordinator or Transmission Planner may choose to simulate a P4 and P5 as one study using the longest expected clearing time. However**,** in the event of a bus fault followed by a bus differential protection failure, there may be a single relay (ANSI device 86) communicating to several breakers attached to the faulted bus. A bus fault on a breaker and a half configuration or double breaker double bus configuration may be particularly problematic in this case. For the Category P5 Event simulating this type of Protection System failure, none of the breakers which should open to clear the fault will receive the appropriate signal from the failed SPF relay and will not clear the bus fault. This makes the bus differential P5 Event significantly more severe than the P4 Event. The FERC Order 754 Section 1600 Data Request was specific to bus faults followed by a SPF of the Protection System.

In some cases, a P4 Event simulation at a specific location will be the same as the P5 Event simulation. For example: the failure of a control circuitry associated with a breaker trip coil results in the same analysis as the P4 for the breaker failing to open to clear a fault. Therefore, the P4 Event and the P5 Event may simulate the identical causality. However, if this simulation results in a performance requirement violation, the CAP must include mitigations for the P4 Event as well the P5 Event.

## Extreme Events 2e-2h listed from the stability column of Table 1

Analysis of the data collected under the FERC Order No. 754 Section 1600 Data Request demonstrates the existence of a reliability risk associated with SPF in Protection Systems. Further, while the analysis shows that the risk from SPF is not an endemic problem and instances of SPF exposure are lower on higher voltage systems, the risk is sufficient to warrant further consideration. Risk-based assessment should be used to identify Protection Systems of concern (i.e., locations on the BES where there is a susceptibility to cascading if a Protection System component SPF exists). Given the risk to BES reliability, additional emphasis should be placed on assessment of three-phase faults involving a SPF on the Protection System. This concern, made manifest through the study of a three-phase fault and a SPF on a Protection System, is appropriately addressed as an extreme event in TPL-001-5, Requirement R4, Part 4.2. While less probable than SLG faults, three-phase faults frequently initiate as single-phase-to-ground with Delayed Fault Clearing and often evolve into three-phase faults, leading to Delayed Fault Clearing scenarios more severe than the Table 1, Category P5 Event. TPL-001-5, Requirement R4, Part 4.2, specifies that an evaluation of possible mitigating actions be conducted if analysis concludes there is cascading caused by the occurrence of extreme events. Thus, the SDT has maintained the three-phase-fault given a Protection System component SPF as an extreme event, but encourages consideration of implementing mitigating actions if it is cost-effective to do so.

## Requirement R3, Parts 3.2 and 3.5 and Requirement R4, Parts 4.2 and 4.5

The SDT proposes non-substantive editorial changes to combine part of Requirement R3, Part 3.5 with Requirement R3, Part 3.2. The rearrangement of Requirement 3, Parts 3.2 and 3.5 were done to improve consistency within the Standard and do not create any new requirements. This is also true for Requirement R4, Part 4.2 and 4.5. However, it should be noted that the evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the (extreme) event is intended to support and encourage the implementation of reasonable, cost-effective measures to lessen the risk or severity of these events.

# Section 2: FERC Order No. 786 Directives

## Background

In addition to addressing reliability issues involving SPF on Protection Systems, proposed Reliability Standard TPL-001-5 revises the TPL-001 standard to address two directives from FERC Order No. 786.

### FERC Order No. 786 P. 40: Maintenance outages in the Planning Horizon

FERC Order No. 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. Order No. 786 provides the following considerations:

- 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. 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.

### NERC SAMS Whitepaper Recommendations

To address this directive, the NERC SAMS recommended modifications to NERC Reliability Standards IRO-017-1 and TPL-001-4. The SAMS recommended that IRO-017-1 be used as the vehicle to assure that all types of known scheduled outages are being reviewed and coordinated to mitigate reliability impact as the most cost-effective means to address the intent of the NERC directive. The NERC SAMS also recommended modifying TPL-001-4, Requirement R1, Part 1.1.2 by removing “with duration of at least six months” and adding language referencing the outage coordination process developed in IRO-017-1, Requirement R1 as described above.

To understand the relationship between outage coordination and Transmission Planning Assessments, and how those relate to the FERC Order No. 786 directive and the current state of NERC Reliability Standards, SAMS considered the following:

- The duration of planned maintenance and construction outages can range from hours to many months or years. The impact that these outages can have on reliable operation of the BPS are irrespective of the duration of these outages, depending on many factors.
- Longer-term assessment of short-term outages or even longer-term outages is often considered an “academic exercise” due to concurrent outages, outage coordination practices and procedures, outage rescheduling and redesign, and alternative outage methods.
- The directives in FERC Order No. 786 pre-date the development of IRO-017-1, which was developed specifically to recognize the importance of outage coordination.
- Regional differences result in different outage coordination methods and procedures.

# Revisions to TPL-001-4

## Requirement R2, Parts 2.1.4 and 2.4.4

The SDT gave due consideration to the NERC SAMS recommendations and to a range of opinions and options regarding how to determine which known outages to include in the Near-Term Planning Assessment, which included varying, and sometimes conflicting, perspectives, such as that:

- the RC should not be consulted or involved at all in Planning Assessments,
- it is reasonable, appropriate, and efficient to consult with the RC,
- IRO-017 is adequate and applicable as it exists or with some modification, or
- maintenance outage selection for planning purposes should be at the sole discretion of the Transmission Planner or Planning Coordinator.

The range of these options reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these types of outages. Those differences contribute to a legitimate difficulty in designing a reasonable and cost-effective continent wide means of addressing the FERC directive. However, FERC Order No. 786 requires that the issue be addressed. The rationale for selecting the known outages to be studied must be well thought out and available. The proposed modification is for consideration of known outages beyond, and therefore outside of, the Operations Planning time horizon.

The most prominent change the SDT proposes to address the FERC directive was to migrate the assessment of known outages from Requirement R1, which requires that System models shall represent, to Requirement R2, Parts 2.1 and 2.4 which requires how analyses shall be assessed and supported by studies. The SDT believed that this proposed change to where the assessment of known outages is specified in the TPL-001-5 requirements better aligns the approach necessary for the planning entities to execute their annual Planning Assessments.

The SDT modified Requirement R2, Part 2.1.4 and 2.4.4 consistent with FERC's directive, eliminating the specified six month outage duration and recognizing the various means that Planning Coordinators and Transmission Planners currently employ to consider the maintenance outages of concern, while meeting the requirements of Order No. 786. The proposed modifications place limitations on the known outages that need to be considered. The Planning Coordinator and Transmission Planner must have either a documented outage coordination procedure or technical rationale to select which known outages shall be assessed. The documented outage coordination procedure is intended to include consultation with the affected Reliability Coordinator, consultation with Transmission and/or Generator Owner(s) affected by the known outage, or application of documented outage coordination processes. The technical rationale is intended to include well-reasoned technical bases for making the determination. Consistent with the intention of Order No. 786, the SDT included the specification that the limitation of known outages to be modeled cannot be based solely on the outage duration. However, the presence of other accompanying factors, which in conjunction with outage duration, may form a reasonable basis for supporting that the known outage need not be assessed. It is only necessary to consider known outages expected to cause more severe System impacts, such as those that may result in Non-Consequential Load Loss for P1 event in Table 1. This allows the Planning Coordinator and Transmission Planner to use applicable means to assess which known outages are significant and prevents the need for conducting unnecessary assessment of outages which the Planning Coordinator and Transmission Planner do not expect to be problematic. The System conditions, such as peak or Off-Peak, that are expected during the period when the known outage is planned further limits the "non-hypothetical" analyses that may be performed. While it is inappropriate to assume that all known outages simulated in conjunction with Category P0 or P1 Events are identical to Category P3 or P6 Events, past or current studies may support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1 . However, it is imperative for the Planning Coordinator or Transmission Planner to document the justification for supporting the known outage exclusion based upon past or current studies and why the post-Contingency System conditions and configuration are comparable in their technical rationale.

### *Clarification: Does TPL-001-5 duplicate requirements of IRO-017-1 for outage coordination?*

The SDT was concerned that in order for 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, it must first assess the known outages as part of that Planning Assessment. However, if the Planning Coordinator or Transmission Planner does not know what outages to study, clearly outages may be omitted from having the opportunity for jointly developed solutions with the Reliability Coordinator, required in IRO-017-1. The SDT believed that the feedback loop between the planning entities and the Reliability Coordinator ends with the planning entities presenting their study results in the Planning Assessment, but must begin with strong collaboration and sourcing of information regarding known outages that should be studied beyond the Operations Horizon by the Reliability Coordinator. Therefore, the SDT does not believe that there is duplication between the proposed TPL-001-5 and IRO-017-1 standards. Moreover, the SDT believes there is an implied need to strengthen the collaboration and consultation between the Reliability Coordinator and the planning entities at the outset of determining the known outages that should be assessed in the Near-Term Transmission Planning Horizon.

## FERC Order No. 786 P 89: Dynamic assessment of outages of critical long lead time equipment

In paragraph 89 of Order No. 786, FERC stated:

> The spare equipment strategy for steady state analysis under Reliability Standard TPL-001-4, Requirement R2, Part 2.1.5 requires that steady state studies be performed for the P0, P1 and P2 categories identified in Table 1 with the conditions that the system is expected to experience during the possible unavailability of the long lead time equipment. The Commission believes that a similar spare equipment strategy for stability analysis should exist that requires studies to be performed for P0, P1 and P2 categories with the conditions that the system is expected to experience during the possible unavailability of the long lead time equipment.

FERC did not direct a change but did direct NERC to consider this issue upon the next review cycle of TPL-001-4. The Project 2015-10 Standard Authorization Request included this issue within the scope of this project.

### *Clarification: Does TPL-001-5 prescribe an entity's spare equipment strategy?*

No. The SDT addressed the guidance in paragraph 89 of Order No. 786 regarding stability analysis to assess System performance for conditions expected during possible unavailability of long lead time equipment in TPL-001-5 Requirement R2, Part R2.4.5. The SDT recognized that "spare equipment strategy" is not a NERC-defined term and believed it was sufficient to allow flexibility for applicable entities to conduct both steady state and stability analysis required by TPL-001-5 Requirement R2, Parts R2.1.5 and R2.4.5. For example, an entity's spare equipment strategy may include the warehousing of a replacement transformer to be installed given the failure of an in-service BES transformer. When an entity's spare equipment strategy may prevent major Transmission equipment from being out-of-service for one year or more, this possible equipment unavailability need not be assessed as part of TPL-001-5 Requirement R2, Parts R2.1.5 and R2.4.5.

## NERC SAMS Whitepaper Recommendations

The NERC SAMS considered the following key points related to FERC's Paragraph 89 guidance:

- Removal of Elements in the Planning Assessment for spare equipment strategy is only applicable for those Elements that have “a lead time of one year or more.”
- Each long-lead time Element that is removed from service creates a new operating condition considered the “normal” (P0) condition for Table 1. The applicable contingencies will be studied with that Element removed from service in the pre-contingency state for stability analysis. For example, if a long-lead time transformer does not have a spare, it would be studied as a P1.3 event. Since P0 does not include an Event, P0 does not and should not be included in the stability analysis section for long-lead time Elements not included as part of a spare equipment strategy.
- System adjustments may need to be made to the power flow base case to accurately reflect reasonable and expected operating conditions with that Element removed from service in the pre-contingency (P0) operating state.
- TPL-001-4, Requirement R4, Part4.1.1, related to P1 Events, requires that no generating unit pull out of synchronism. The outage of a long-lead time Element followed by a P1 contingency should not result in a generating unit losing synchronism.
- TPL-001-4, Requirement R4, Part 4.1.2, related to P2 Events, allows for generating units to pull out of synchronism. The outage of a long-lead time Element followed by a P2 contingency should not result in tripping of any Transmission System Elements other than the generating unit and its directly connected Facilities.

The NERC SAMS white paper contains the flowing recommendations for stability analysis for long lead time Elements not included as part of a spare equipment strategy:

- The outage of long lead time Elements has an equally important impact from a stability standpoint as it does from a steady-state standpoint.
- The Planning Coordinator and Transmission Planner must demonstrate that they have met the TPL-001-4 performance criteria for specified contingency events and contingency combinations thereof as per Table 1. This should include long lead time outages that can occur for equipment that does not have a spare equipment strategy.
- TPL-001-4, Requirement R4, Part4.1.1 requires that no generating unit pull out of synchronism, while R4.1.2 allows for generating units to pull out of synchronism so long as the resulting instability does not result in tripping of any Transmission System Elements other than the generating unit and its directly connected Facilities. The outage of a long lead time Element followed by a P1 contingency should not result in a generating unit losing synchronism.
- While the P2 contingency allows for individual generating unit instability, the Transmission Planner and Planning Coordinator must ensure that this instability does not result in tripping of any Transmission System Elements other than the generating unit and its directly connected Facilities and therefore should include P2 contingencies event.

# Revisions to TPL-001-4

## Requirement R2, Part 2.4.5

Consistent with FERC’s Order No. 786 guidance and the SAMS recommendations, the Project 2015-10 SDT revised TPL-001-4 Requirement R2, Part 2.4.5 to add a similar requirement for stability analysis. The change to Requirement R2, Part 2.4.5, which includes similar language to that used for the steady-state analysis under Requirement R2, Part 2.1.5, adds clarity that the outage of long lead time Elements has an equally important impact from a stability standpoint as it does from a steady-state standpoint and should be assessed commensurate with an entity’s spare equipment strategy.

# Section 3: Applicability

The requirements remain applicable to the Planning Coordinator and Transmission Planner. Coordination and cooperation between operating and planning entities in concert with asset owners will be required to implement the standard requirements. The planning entities and System Protection personnel that will need to collaborate when conducting the studies and submitting the data may be working for different companies or business units, and time will be required to accommodate the development of processes and data flow that cross company or business unit lines. Coordination with Generator Owners, Transmission Owners, and Distribution Providers will be necessary to evaluate the Protection System(s) for locations on the system where a failure of a non-redundant component of a Protection System could result in a potential reliability risk. Transmission Planners and Planning Coordinators must obtain this information, as well as resulting fault clearing times, to perform proper studies.