Protection System Redundancy Criteria for NERC TPL-001.5 Footnote 13

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Abstract

NERC Standard TPL-001.5.1 is not a Protection and Control standard, however it's footnote 13 is about redundancy of four of the five elements of the NERC defined Protection System. Most protection engineers are not familiar with the nuances of the defined requirements for redundancy or monitoring exemptions for elements such as DC supply and control circuitry. Some Protection engineers assume that compliance groups or planning groups, (Planning Coordinator or Transmission Planner), have this responsibility but in many cases those groups lack the detailed knowledge of control circuits and battery monitoring systems to understand where designs are deficient in meeting the requirements. The standard does not require redundancy in all cases but requires utilities to identify BES locations where any of the four redundancy tests are not met and to provide backup fault clearing times, breakers and thevenin impedances for sequentially clearing three phase and single line to ground faults. The authors have made presentations to WECC and NERC Relay Working Groups on some of the issues regarding footnote 13. Footnote 13 is a follow on effort based on the earlier FERC Order No. 754.

This paper and presentation will focus on identifying the NERC redundancy requirements for TPL-001.5.1 footnote 13 a, b, c and d. The most common redundancy failures for WECC utilities will be discussed. Data management and best practices will be addressed. These will focus on battery monitoring requirements and control circuit issues. In many cases non redundancy is allowed if the element is monitored and reported to a Control Center. Authors will discuss problems encountered while trying to provide evidence of compliance for the monitored and reported option. New databases or data repositories typically need to be created for some of the elements covered by footnote 13. Some common incorrect assumptions by planning groups will also be discussed as well as some approaches to streamline the simulation of backup clearing times.

The author's employer has submitted a NERC standards authorization request (SAR) to modify requirement 13d that has been accepted and assigned to a Standard Drafting Team.

I. Introduction

Pacific Gas and Electric

Pacific Gas and Electric (PG&E) is an investor owned vertically integrated electric and gas utility serving most of northern and central California. PG&E has 5.4 million electric accounts and serves a population of approximately 16 million. The asset base at PG&E includes 107,000 circuit miles of overhead and underground electric distribution lines; 18,443 circuit miles of electric transmission operating at 500 kV to 60kV, 2.4 million distribution poles, 3,200 feeders, 140,000 transmission structures and more than 7,000 MW of company owned generation.

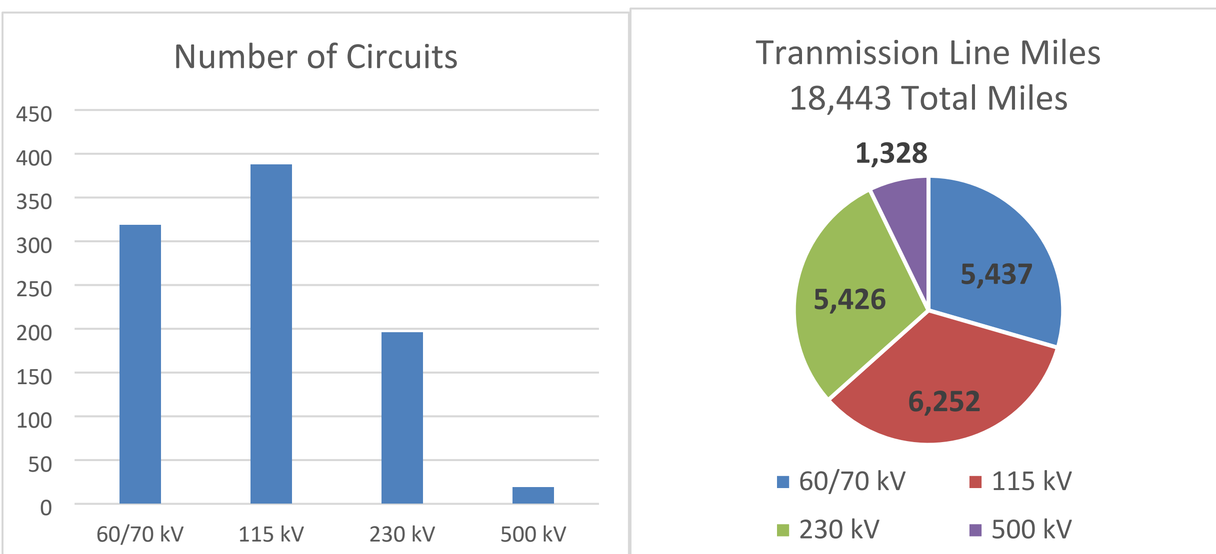

Figure 1 - Number of PG&E Transmission Circuits and Mile of Transmission Lines by Voltage

The cost and impact of complying with NERC standards at PG&E is enormous and a commensurate amount of resources are applied to ensure compliance. The significant changes in Protection System redundancy requirements that were added to NERC standard TPL-001.5.1 largely was under the radar of protection practitioners. No protection engineers were included on the Standard Drafting Team (SDT).

Previous NERC standard TPL-001-4 required companies to perform transmission planning studies on the steady state and stability impacts to the Bulk Electric System (BES) of delayed fault clearing times for failure of non-redundant protective relays (Category P5 outages) with a Single

Line to Ground (SLG) fault as the minimum requirement. NERC TPL-001-5.1 added three additional elements of the NERC defined Protection System to analyze for non-redundancy for steady state and stability studies (expanded Category P5 outage scope).

Protection engineers usually have sufficient compliance responsibilities keeping up with NERC PRC standards -002 to -027 and other incidental compliance responsibilities with CIP and others that they do not feel the need to become subject matter experts on the two NERC TPL standards. However, there are several elements of TPL-001-5.1 with which protection engineers need to be familiar and interface with their transmission planning group to ensure that correct assumptions and data are being used for the required studies.

The main body of the standard includes some items that are of interest to protection engineers such as R2.3 which requires annual studies of the Near-Term Planning Horizon (5 years forward looking) to determine whether circuit breakers can interrupt expected fault currents with planned system changes. R2.4.5 includes language on spare equipment strategy for equipment with lead times longer than one year. R2.8 requires a Corrective Action Plan (CAP) for breakers identified as overstressed in the Near-Term Planning Horizon. R4.3.1.1 requires an analysis of high speed reclosing into a fault.

The tables and footnotes that are included with the standard are probably the best resource for protection engineers to review to gain a general understanding of the studies that need to be performed by transmission planners and what data needs to be provided by protection for transmission planning to perform accurate steady state and transient stability studies. Many of these tables and footnotes are included as figures on the following pages.

Most of the required annual assessment studies are split into “Planning” outage categories labeled P1 through P7. These require studies of steady state and transient stability under different outage conditions. Typically, the studies require 3 phase or SLG faults with variables such as faults on different power system elements, stuck breakers, or delayed clearing due to one of the failures of a non-redundant element of the Protection System detailed in Footnote 13 of TPL-001-5.1 (Category P5).

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

Figure 2 - TPL-001-5.1 Table 1 Steady State & Stability Performance Planning Events, page 20

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault[8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker)[8]	SLG	EHV, HV	Yes	Yes

Figure 3 - TPL-001-5.1 Table 1 Steady State & Stability Performance Planning Events (P0-P2), page 21.

Note that for P2 studies, transmission planners are required to simulate single line to ground (SLG) faults for stability studies at a minimum. The most common software in the Western Interconnection to perform stability studies is GE PSDS (Positive Sequence Dynamic Simulation).

This software uses only a positive sequence impedance model but is often used to simulate the impact of SLG faults. This may result in some error or uncertainty in the results, though this error can be reduced slightly by including a Thevenin equivalent fault impedance from fault study models.

There are some basic relay functions and timing options that can be modeled in PSLF (Positive Sequence Load Flow) software, though many planning groups use default definite clearing time assumptions which may not always be correct.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker[10](non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes

Figure 4 - TPL-001-5.1 Table 1 Steady State & Stability Performance Planning Events (P3-P4), page 22.

Though TPL-001.5.1 does not directly address breaker failure relaying or the failure of breaker failure relaying, some of the requirements for studies can use breaker failure relaying to provide faster and more uniform tripping times. Some of the failures of protection system elements may not result in breaker failure relay operations, and the associated outages are likely to be misrepresented by transmission planners who may not be familiar with the results of breaker failure relay operations. Those examples will be detailed later in the paper.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P5 Multiple Contingency *(Fault plus non-redundant component of a Protection System failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer[5] 3. Shunt Device[6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

Figure 5 - TPL-001-5.1 Table 1 Steady State & Stability Performance Planning Events (P5-P7), page 23 and 24.

The P5 outages require the most attention from protection and control engineers, though all outage types specifying SLG faults are worthy of careful consideration. The P5 outages require studies to be performed for specific SLG faults with delayed clearing due to the failure of a NERC defined non-redundant component of a Protection System. See the small footnote 13 shown in Figure 5 above. Most of this paper will detail what the authors believe is required to meet the footnote 13 definition of non-redundant components of the Protection System, problems with obtaining data on non-redundancies and some of the most common redundancy challenges at utilities based on professional experience and formal and informal surveys of and conversations with other protection experts in the U.S.

Table 1 – Steady State & Stability Performance Extreme Events	
Steady State & Stability For all extreme events evaluated: a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency. b. Simulate Normal Clearing unless otherwise specified.	
Steady State 1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments. 2. Local area events affecting the Transmission System such as: a. Loss of a tower line with three or more circuits.[11] b. Loss of all Transmission lines on a common Right-of-Way[11]. c. Loss of a switching station or substation (loss of one voltage level plus transformers). d. Loss of all generating units at a generating station. e. Loss of a large Load or major Load center. 3. Wide area events affecting the Transmission System based on System topology such as: a. Loss of two generating stations resulting from conditions such as: i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation. ii. Loss of the use of a large body of water as the cooling source for generation. iii. Wildfires. iv. Severe weather, e.g., hurricanes, tornadoes, etc. v. A successful cyber attack. vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants. b. Other events based upon operating experience that may result in wide area disturbances.	**Stability** 1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments. 2. Local or wide area events affecting the Transmission System such as: a. 3Ø fault on generator with stuck breaker[10] resulting in Delayed Fault Clearing. b. 3Ø fault on Transmission circuit with stuck breaker[10] resulting in Delayed Fault Clearing. c. 3Ø fault on transformer with stuck breaker[10] resulting in Delayed Fault Clearing. d. 3Ø fault on bus section with stuck breaker[10] resulting in Delayed Fault Clearing. e. 3Ø fault on generator with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing. f. 3Ø fault on Transmission circuit with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing. g. 3Ø fault on transformer with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing. h. 3Ø fault on bus section with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing. i. 3Ø internal breaker fault. j. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

Figure 6 - TPL-001-5.1 Table 1 Steady State & Stability Performance Extreme Events, page 25 and 26.

Figure 6 shows extreme events that planners may need to analyze. Some of these events are rare and improbable (e.g. three phase internal breaker fault, three phase transformer fault, or three phase generator fault followed by a stuck breaker) but these may still require steady state and/or stability analysis based on the judgment of the transmission planners in selecting outages expected to have more severe impacts on the transmission system.

Figure 7 below shows that TPL-001-5.1 is now in effect and that the first round of studies must have been completed by 7/1/2023. Companies are required to perform annual assessments under TPL-001-5.1, and most companies choose to align these annual assessments with the calendar year.

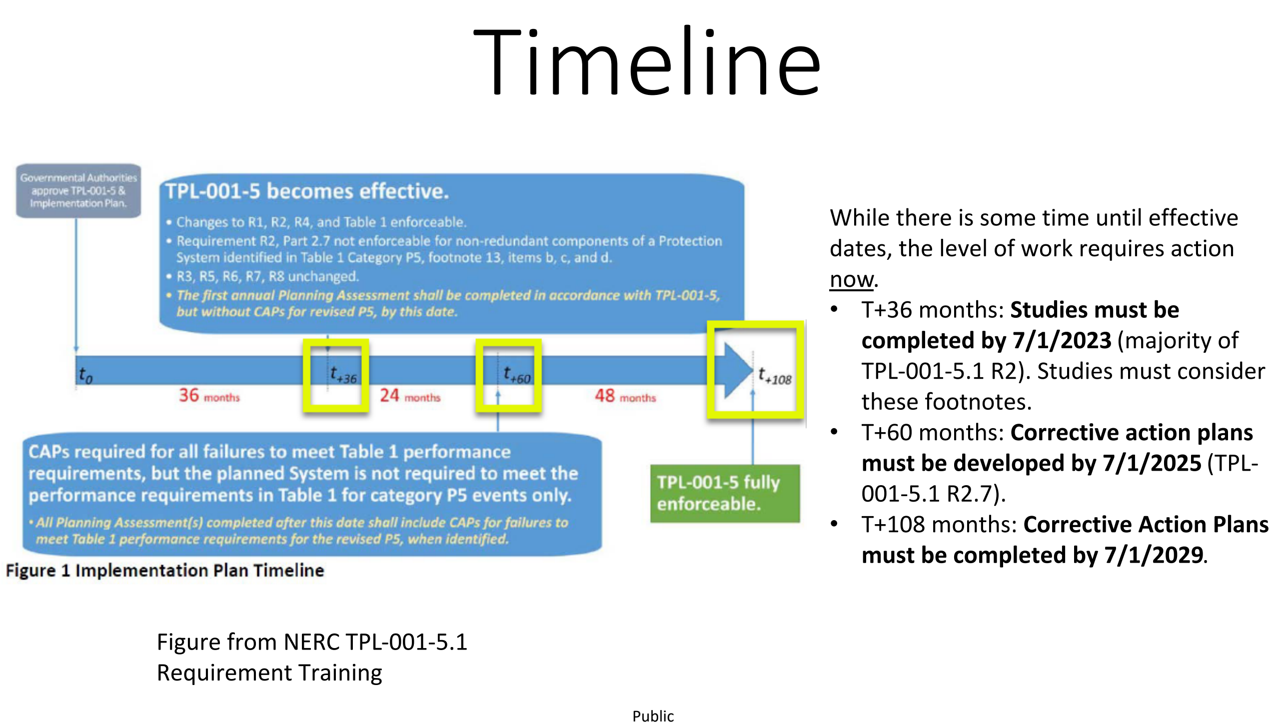

Figure 7 - TPL-001-5.1 Implementation Compliance Deadline

Corrective Action Plans (CAPS) for the P5 outages newly included in TPL-001-5.1 must be developed by 7/1/2025 and any deficiencies must be resolved by having the identified CAPs completed by 7/1/2029.

This may sound like a very long implementation window, but for some companies, this time frame will be extremely difficult to meet due to the number of projects and timelines required.

TPL-001.5.1 Footnote 13

TPL-001.5.1 Page 28 contains footnote 13 which details what non-redundant components of the Protection System must be considered for P5 studies.

Planning studies are mandatory, but redundancy is not mandatory. Unlike most PRC standards, the redundancy elements in footnote 13 are not prescriptive or mandatory requirements. Planning studies are required that must account for the failure of non-redundant elements as measured by the terms laid out in footnote 13 a-d. Identification of the non-redundant elements expected to produce more severe system impacts is required by the standard.

Even though redundancy of Protection System elements is not required by this standard, where planning studies identify deficiencies making upgrades to Protection System elements is typically the most cost effective means of correcting those deficiencies.

Footnote 13: For purposes of this standard, non-redundant components of a Protection System to consider are as follows:

> a. A single protective relay which responds to electrical quantities, without an alternative (which may or may not respond to electrical quantities) that provides comparable Normal Clearing times;
>
> b. A single communications system associated with protective functions, necessary for correct operation of a communication-aided protection scheme required for Normal Clearing (an exception is a single communications system that is both monitored and reported at a Control Center);
>
> c. A single station dc supply associated with protective functions required for Normal Clearing (an exception is a single station dc supply that is both monitored and reported at a Control Center for both low voltage and open circuit);
>
> d. A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions, from the dc supply through and including the trip coil(s) of the circuit breakers or other interrupting devices, required for Normal Clearing (the trip coil may be excluded if it is both monitored and reported at a Control Center).

Footnote 13 is the portion of TPL-001-5.1 that is of primary interest to protection engineers. Previous standard TPL-001-4 only included a check for non-redundancy in protective relays. The components of the NERC defined Protection System added to TPL-001-5.1 are detailed in footnote 13 b, c, and d. This has added checks for non-redundant communication systems associated with protective functions, DC supplies and control circuitry. CT and PT sources are included in the NERC defined Protection System, but their failure or redundancy level are not considered for TPL-001-5.1.

At many companies, protection engineers are not the asset owners or create standards governing all components of the NERC defined Protection System. It may be necessary for many different groups to become familiar with the details of this footnote, other references found in Project 2015-10 - Technical Rationale for TPL-001-05, and FERC Order 754.

Footnote 13 Monitored and Reported Options

One crucial difference between the four components of the Protection System covered in footnote 13 is the language for exceptions to redundancy for elements that are monitored and reported to a Control Center. This language is highlighted in the copy of footnote 13 above.

In most cases it will be less expensive to use a monitoring option if redundancy does not already exist.

13a - Protective relays - Does not allow an exception for monitored and reported relay failures.

13b – Allows a single communication system if (failures) are monitored and reported to a Control Center. The exception language applies to the entirety of the communication system. No details are provided on what components of the communication system must be redundant to meet this requirement.

13c – A single DC supply is allowed if it is monitored and reported to a Control Center and the monitoring meets the requirements laid out in the technical rational document. The exception language applies to the entirety of the DC supply.

13d – The monitored and reported exception for non-redundant control circuitry is profoundly different from 13 b or c. Control circuitry includes many components: DC panel, DC circuits, wires to the relay panels, auxiliary relays, and lockout relays used as part of the Protection System. Trip wires going from the control house to the circuit breaker and the trip coil in the circuit breaker. **The exception for monitoring and reporting only applies to the trip coil and not to any of the other components.** This renders the exception for monitoring and reporting of no practical value for footnote 13d.

Protection Engineers at many utilities have not been included in detailed compliance discussions for TPL-001.5.1 In some cases, assumptions that are not supported by the standard language or supporting material are applied or overly optimistic assumptions are made about redundancy, delayed clearing times and which breakers will operate.

Some companies may point to existing breaker specifications and protection standards as evidence that they have full redundancy. The NERC standards do not apply only to current utility practices. They also apply to the oldest equipment in the smallest and most remote BES stations. Likewise for any monitored and reported exceptions. Evidence of compliance for individual alarm points from all non-redundant components to a Control Center may be required by auditors.

Common Problem Areas for Footnote 13

13a. A single protective relay which responds to electrical quantities, without an alternative (which may or may not respond to electrical quantities) that provides comparable Normal Clearing times.

At BES voltages most newer relay installations are redundant. (i.e. two microprocessor line relays.) There are some common problems areas regarding protective relay redundancy.

Bus Differential Relaying

Many companies have some installations with a non-redundant bus differential scheme. The failure of a non-redundant bus differential scheme during a SLG bus fault is one of the more significant issues considered under TPL-001.5.1. If a single level of bus differential scheme fails to operate for a SLG bus fault, it will not initiate breaker failure relaying. It will require the operation of remote line relays and local bank relaying elements in order to be cleared. If the use of ground distance with common time delays is not applied universally, then multiple remote clearing times must be determined for ground time overcurrent elements. As each backup terminal trips the fault current is redistributed from the remaining sources which changes the remaining trip time calculations. For large busses, modeling these multiple breaker sequential tripping times and sequences and providing the data to transmission planners is very time consuming. Some companies provide software to assist with this labor-intensive work.

No exclusion for protective relays for monitoring or alarming is given.

Many electromechanical relays and some solid state and microprocessor relays may lack redundancy. If four Electromechanical directional or non-directional relays are applied on a line terminal, some built in redundancy exists. At BES voltages, distance relays are much more common. These generally do not have any inherent redundancy for the failure of a single relay.

BES Transformer relaying can also have redundancy issues. Older relay installations may only apply a single differential relay. This may be considered redundant if additional relays are applied which provide comparable normal clearing times. This could be supplied by a sudden pressure relay or primary and secondary instantaneous elements. Even two microprocessor differential relays may not have complete redundancy for some faults. If the differential elements for one relay are connected to bank bushing CT's and a second differential relay is connected to circuit breaker CT's, a fault on the bushings or lightning arrestors with a failed outer differential relay may result in delayed clearing.

13b. A single communications system associated with protective functions, necessary for correct operation of a communication-aided protection scheme required for Normal Clearing (an exception is a single communications system that is both monitored and reported at a Control Center);

A single communication system used to be the norm for non EHV, BES lines at many companies. With the increased application of digital communications, it has become much less expensive to add a second level of communication aided tripping for lines.

Direction comparison blocking schemes have become less common over the last several decades due to concerns about their security. They are unique in that a failure of the communication equipment may still result in a high speed trip. The failure of a non-redundant directional comparison blocking scheme may not result in delayed tripping.

All other communication aided tripping schemes must be reviewed for redundancy or common failure modes that may affect all levels of communication aided tripping.

As part of the transition from powerline carrier and analog communications to digital communications many protection practitioners have less knowledge about what happens withing the communication "cloud." Some networks are configured as self healing or re-routable systems if latency time requirements are met.

TPL-001.5 and its technical rational document offer very little guidance on redundancy within the digital communication “cloud”. The standard is based on earlier work with frequent use of the term SPOF (single point of failure). At the authors company protection engineers often specify that each level of communication aided tripping can have no common modes or failure or SPOF’s. The expectation is that communication personnel will ensure that this specification is met. In many cases some common failure modes still exist. There are some typical areas of concern that need to be considered as part of a thorough redundancy evaluation:

- Do redundancies exist within a common fiber bundle?
- Are redundant fibers in a common conduit?
- Are redundant circuits within a common trench?
- Does a microwave system use a common dish or tower for redundant circuits?
- Do communication systems use a separate battery system from the normal substation DC supply? Are these communication batteries redundant?

Some Regional Reliability Organizations (NPCC) have prescriptive requirements for redundant communication circuits.

The authors are aware of one company that assumes all communication aided tripping schemes fail and apply backup trip times for all lines. This requires much less data collection but may create some additional failures in the P5 analysis.

One special aspect of communication aided tripping scheme failure is the number of additional lines that may overtrip. Figure 8 below illustrates a fault on a short line in an area with longer lines. The number of overtripping lines may not be considered by transmission planners.

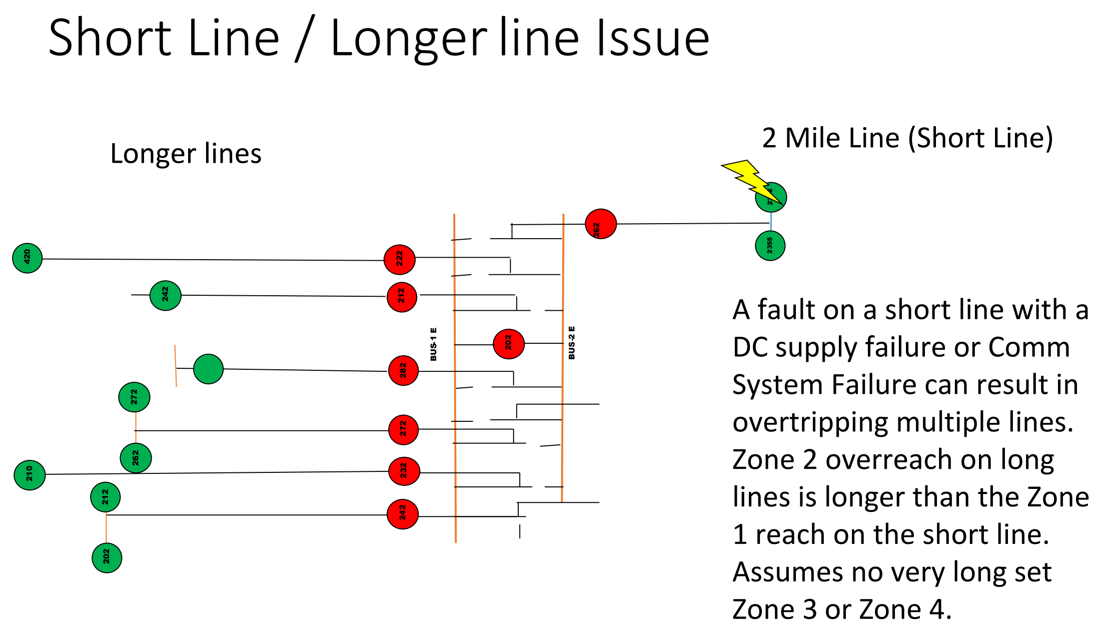

Figure 8 – Overtripping Impact of Failure of Communication Aided Tripping Scheme

One other aspect of footnote 13b may be troublesome. An exception is given for a single scheme that is monitored and reported at a Control Center. The authors believed that all communicated aided tripping schemes at their company would qualify for the monitored and reported exception. In gathering evidence of compliance, it was observed that in some cases alarms were either not transmitted to a Control Center, not displayed for the Control Center operators or the wording of the alarm was so vague that it could not be deduced if it was a failure alarm, cut in indication or a trip target. Auditors could request evidence of compliance if the monitored and reported exception is used.

13c. A single station dc supply associated with protective functions required for Normal Clearing (an exception is a single station dc supply that is both monitored and reported at a Control Center for both low voltage and open circuit)

The requirements for dc supply are fairly straightforward, however many companies misinterpret the monitored and reported requirements for a non-redundant system. Many battery charger manufacturers add to this confusion by claiming their internal charger alarms meet the TPL-001.5 requirements. There are also many different DC supply and DC panel configurations in use in the industry.

Some utilities have redundant DC batteries at all of their BES stations.

Many utilities do not have redundant DC batteries on all BES stations.

The monitoring and reporting exception for a single DC supply can be used. Figure 9 below, is the most instructive about the monitoring requirements. This figure appears in the Technical Rational for TPL-001.5.1 and in previous NERC and FERC documents. This figure provides information about the boundary between the NERC defined DC supply and control circuits. It also shows that the monitoring requirements must include AC source, DC supply and open circuit in battery monitoring.

New battery chargers have sophisticated monitoring and alarming integrated into the battery charger, but these are generally not sufficient to meet the monitoring exception. As can be seen in the figure below, if the battery bank has an open circuit but the battery charger is still feeding relay power supplies and control equipment, it will not pickup up the typical loss of load, undercurrent or DC undervoltage alarms in the charger. Additionally, an open that leaves the batteries fed from the battery charger but all DC panels disconnected, may not result in monitoring alarms. Some utilities may claim that the battery charger will provide redundancy for a failed or open battery bank. This may be sufficient for normal conditions but generally will not be able to provide trip current for multiple breakers during a bus differential operation or breaker failure operation and would not meet the redundancy requirements.

- Do your internal databases contain enough detail to determine which stations have redundant DC supplies?
- Do your databases contain enough detail to determine what monitoring and alarm points are used at each station?
- At some large stations, each BES voltage level may use a separate DC supply, or all BES voltages may use a single DC supply. Can you determine this from your internal databases?

The authors company will apply separate Battery Monitoring Systems to meet the monitoring requirements of TPL-001.5.1.

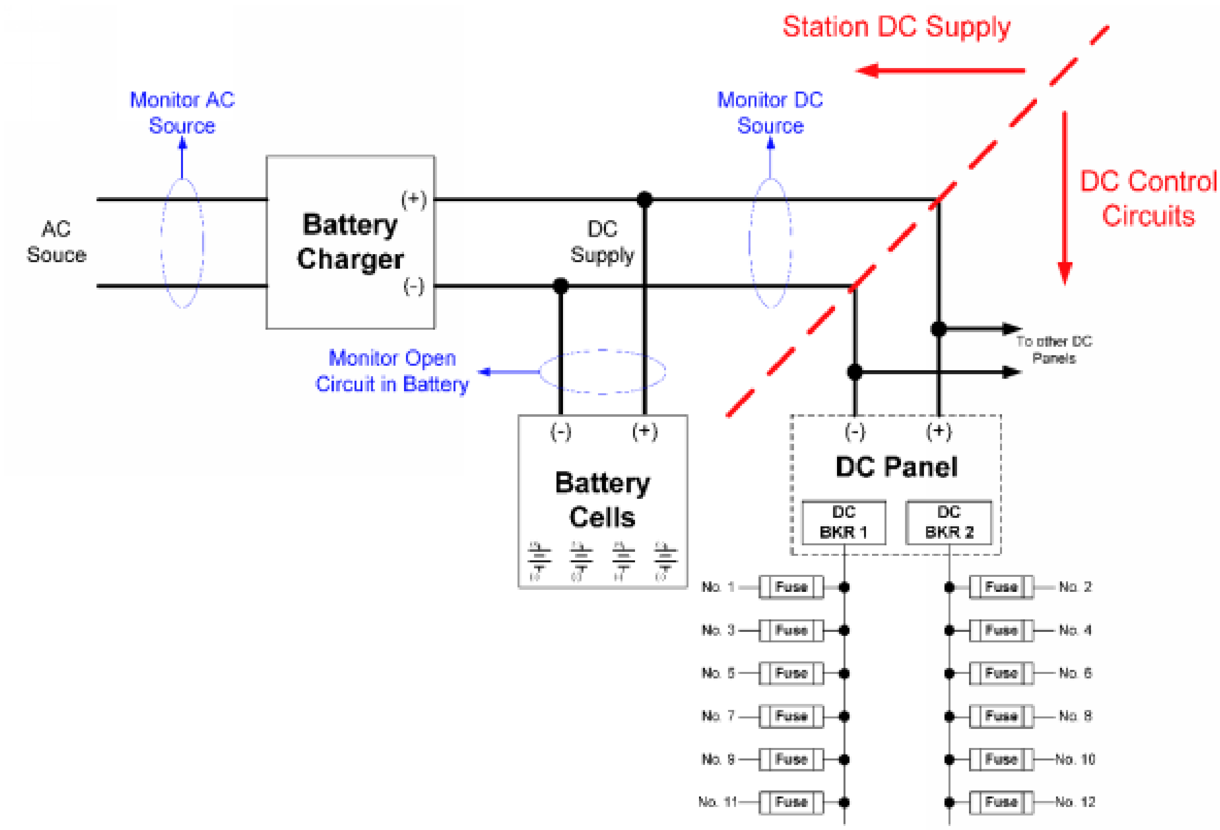

Figure 9. From FERC Order No. 754 and NERC Technical Paper and Technical Rational for TPL-001.5.1.

13d. A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions, from the dc supply through and including the trip coil(s) of the circuit breakers or other interrupting devices, required for Normal Clearing (the trip coil may be excluded if it is both monitored and reported at a Control Center).

Control circuitry in 13d is the most challenging part of footnote 13. There are many different practices used to design DC panels, DC circuits, auxiliary/lockout relays and trip circuits. This could create different demarcations between the DC supply (13c) and control circuitry(13d) depending on each company's design. From Figure 9, control circuitry would typically include the DC panel and from the language in footnote 13d would include all circuitry used for normal tripping from the DC panel to and including the trip coil. The authors believe no gap should exist where equipment is neither part of the DC supply or control circuitry. As mentioned previously there is a distinct difference in the monitoring and reporting exclusion for control circuitry. The only component that can be excluded by monitoring is the trip coil. <u>This implies that all other components of control circuitry must be redundant with no single points of failure.</u>

Most companies specify BES circuit breakers with two trip coils, but many companies still have older legacy circuit breakers with a single trip coil. If a breaker has a single trip coil there is no practical application for the exception of footnote 13d. Two trip wires/trip circuits with no single point of failure cannot be connected to a single trip coil.

Figure 9 clearly indicates that DC panels are to be considered part of the control circuit. Not considering the loss of an entire DC panel or a daisy chained DC panel as a non-redundancy is a questionable practice that would likely not survive scrutiny by auditors. Creating evidence of compliance for control circuit redundancy can become extremely labor intensive. It requires documenting that each BES breaker has two trip coils, wired to separate trip wires (from the control house to the circuit breaker) redundant trip contacts or auxiliary relay contacts that are fed from separate DC circuits each fed from separate DC panels. At most companies, the only way to determine this and create documentation is to have an experienced engineer review detailed schematic prints for every BES breaker. Since equipment may be replaced or new equipment installed this may require creating new databases and processes to capture this data as it changes. TPL-001.5.1 requires annual assessments so processes to document changes in your system are recommended.

Can you trace relay power supply circuits and trip circuits back to a specific DC panel and DC circuit from a database or will it require experienced engineers to review individual DC schematic drawings?

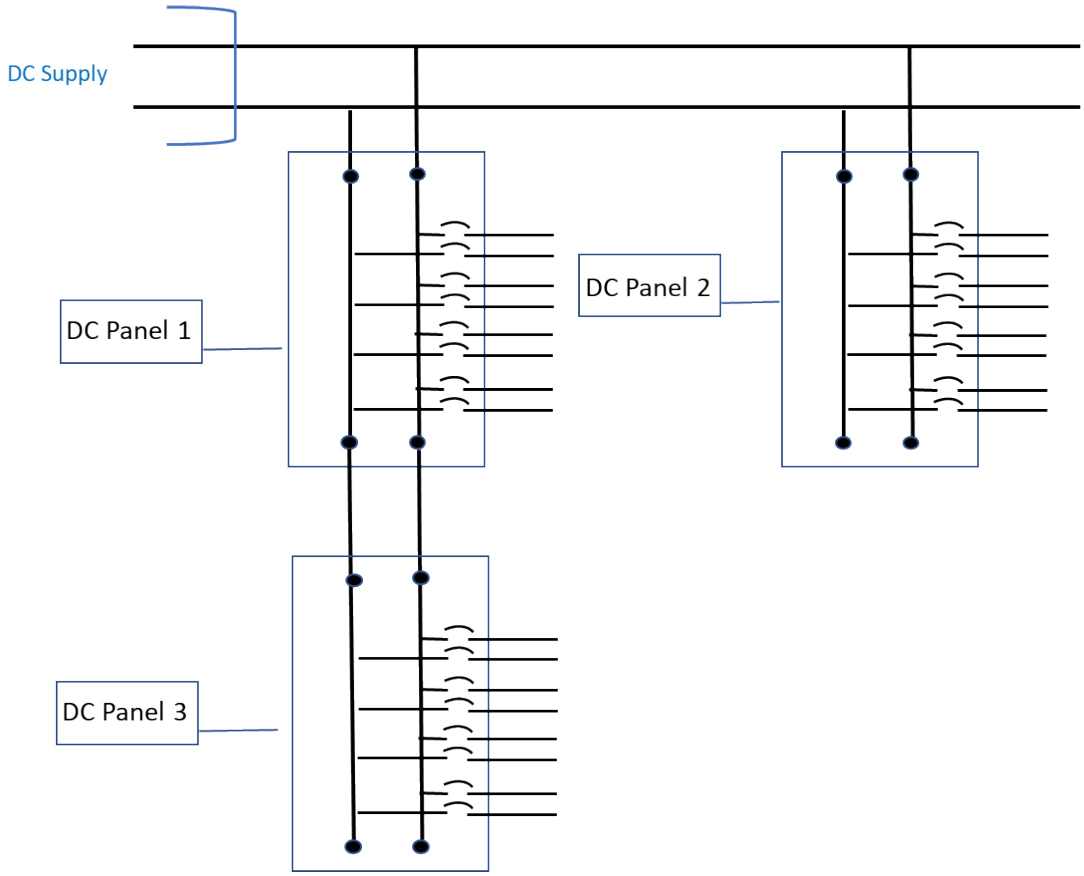

Figure 10. Authors interpretation of DC Panel Redundancy

- If Primary and Backup Relays are both fed from the same DC Circuit, they **fail** redundancy.
- If Primary and Backup Relays are fed from separate circuits on DC Panel 1, they **fail** redundancy.
- If Primary Relay is fed from DC Panel 1 and Backup Relay is fed from DC Panel 3, they **fail** redundancy.
- If Primary Relay is fed from DC Panel 1 and Backup Relay is fed from DC Panel 2, they **pass** redundancy.

Figure 10 shows the authors interpretation of DC panel redundancy (considering a DC panel as a SPOF). Daisy chained DC panels (panel 1 and panel 3) would also be considered as a single point of failure if the first panel fails.

Any auxiliary relays or lockout relays used for normal tripping should also be redundant and fed from separate DC circuits and DC panels to qualify as redundant.

Redundancy of DC panels and DC circuits can to difficult and expensive to achieve. Monitoring and alarming for these non-redundancies can be achieved with moderate cost but is not supported by current standard language.

The vast majority of utilities that monitor trip coils use the same element to monitor the trip wire from the control building to the circuit breaker. Again, the standard language specifically allows a monitoring and reporting exclusion for the trip coil only.

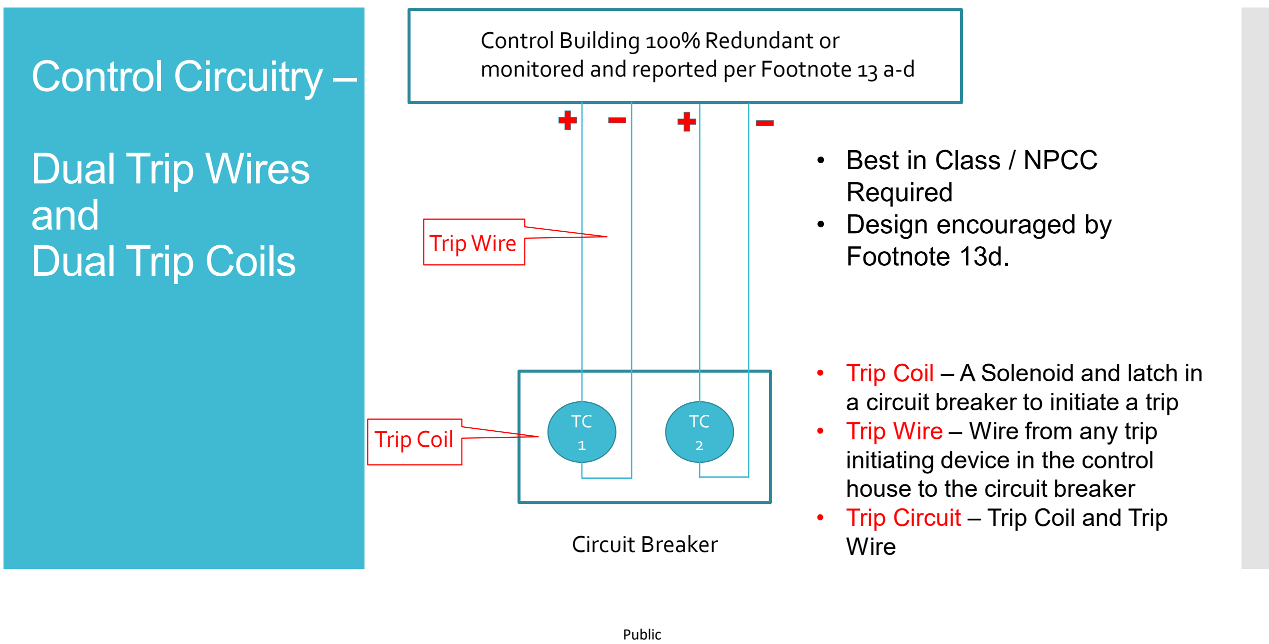

Figure 11. Trip circuit redundancy

Figure 11 depicts trip circuit redundancy which is one of several requirements to achieve control circuit redundancy. In addition, all components inside the control house including DC panels and DC circuits must meet redundancy requirements.

Breakers used in single pole trip schemes would require 6 separate trip coils to achieve redundancy. (Two trip coils per phase)

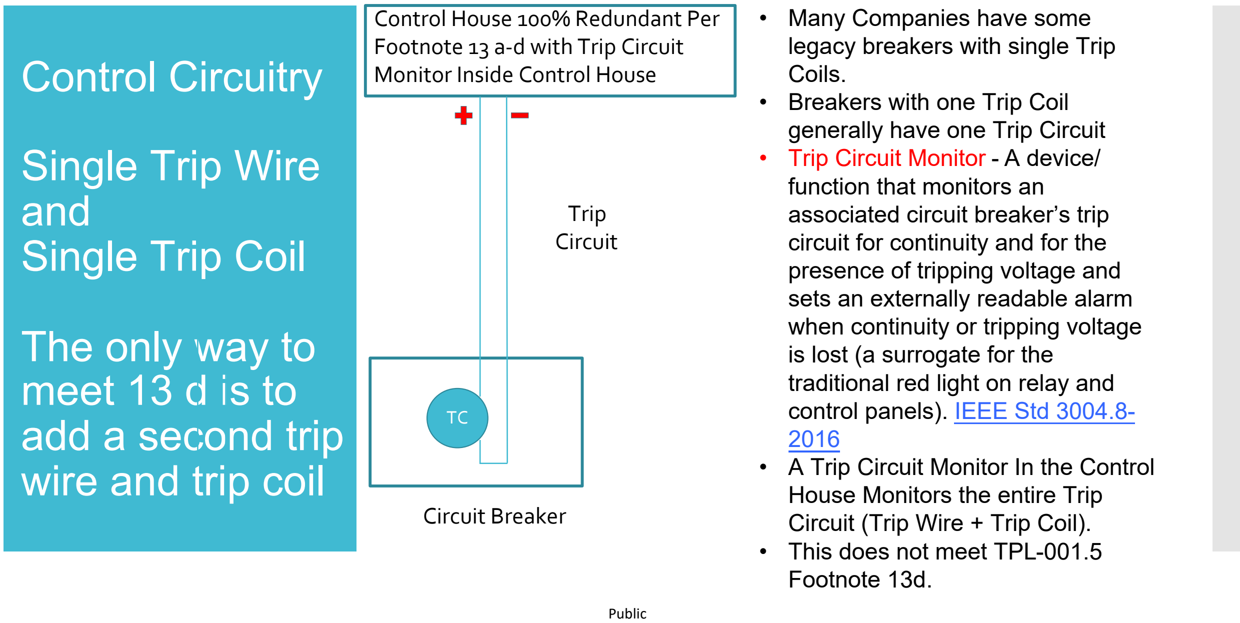

Figure 12. Most utilities have some old breakers with a single trip coil.

Figure 12 depicts the trip circuits on many old breakers with single trip coils. The language in TPL-001.5 footnote 12d would require adding a second trip coil to the circuit breaker and wiring each trip coil to a separate trip wire fed from a different trip contact fed from a separate DC circuit fed from separate DC panels. This could be very expensive and time consuming to accomplish. Investigating the installation of a second trip coil, obtaining and installing the trip coil and in some cases trenching to add conduits or laying new control wire in cable trenches.

Delayed Fault Clearing

After determining which elements of your system do not meet the redundancy criteria detailed in footnote 13 a-d and the technical rational document, you need to work with your transmission planners to make of list of elements to study for normal clearing and delayed clearing.

Footnote 13 applies to the P5 category which specifies SLG faults on your BES system with "Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System protecting the Faulted element to operate as designed.." This may require simulating hundreds of faults, determining which backup breakers will trip and at what trip times. In some cases, breaker failure schemes can provide faster and more uniform trip times but in many cases breaker failure relays will not operate. (Loss of non-redundant DC supply, loss to DC panel feeding redundant relays, loss of non-redundant bus differential relay, etc..). If your system does not utilize ground distance with uniform time delays on all line terminals it is likely that a bus fault with failed normal tripping will require multiple remote terminals to trip by directional ground time overcurrent relay elements. This will result in remote breakers clearing sequentially one by one with each step creating new fault currents, Z thevenin values and relay timing calculations. Determining worst case breaker interrupt time needs to be determined to add to the relay operate times to determine total clearing times for each of these operations. Some companies use different breaker interrupting times at different BES voltage levels.

The authors company manually calculated multi sequential delayed clearing times, breakers, Z thevenin for zero, positive and negative sequences as well as fault currents in 2022. After discussing the labor required for these annual assessments, they contracted with a consulting firm to automate the process of determining these multiple delayed clearing times for a single fault and creating input files for stability studies. See reference section for two papers that detail these efforts.

In some cases, faults may take several seconds to clear or small amounts of fault current remain after 30 seconds. This leads to discussions about the accuracy of leaving conventional generation configured at subtransient reactance for faults that may last for multiple seconds.

Questionable Assumptions

Some questionable assumptions regarding footnote 13 that the authors have seen.

1. All faults with a failed element of the Protection System will clear in 20 cycles.
    a. Many of the studies require SLG faults which often have longer time delays and more variable times if overcurrent elements are applied.
    b. There are often a small number of cases at many utilities where faults with a failed element of the Protection System will remain uncleared.
2. DC alarms from existing battery chargers will meet the monitored and reported option.
    a. Battery charger alarms will generally not meet the requirements for monitoring an open battery circuit. As long as the charger is feeding relays and controls, it remains loaded and does not pickup loss of load or undercurrent elements.
3. DC panel or circuit non redundancy is part of the DC supply.
    a. The figure included in FERC Order 754, NERC Technical Paper on Protection System Redundancy and the Technical Rational for TPL-001.5.1 clearly show that DC panels and circuits are part of the control circuitry.

4. All failures of non-redundant elements of the Protection System will still operate local breaker failure protection.
    a. This is untrue for a single DC supply that fails.
    b. This is untrue for a stuck breaker under many Ring Bus or BAAH configurations without breaker failure direct transfer trip schemes.
    c. A single bus differential scheme that fails will not initiate breaker failure relaying.
5. A bus fault on a Double Bus Single Breaker or Double Breaker with a failure of the bus differential relay will only trip bus tie and bus section tie and remote breakers connected to a single bus/section.
    a. It is very unusual to have normally enabled backup relaying on bus section tie breakers.

Selected Worst Case Scenarios for Delayed Fault Clearing

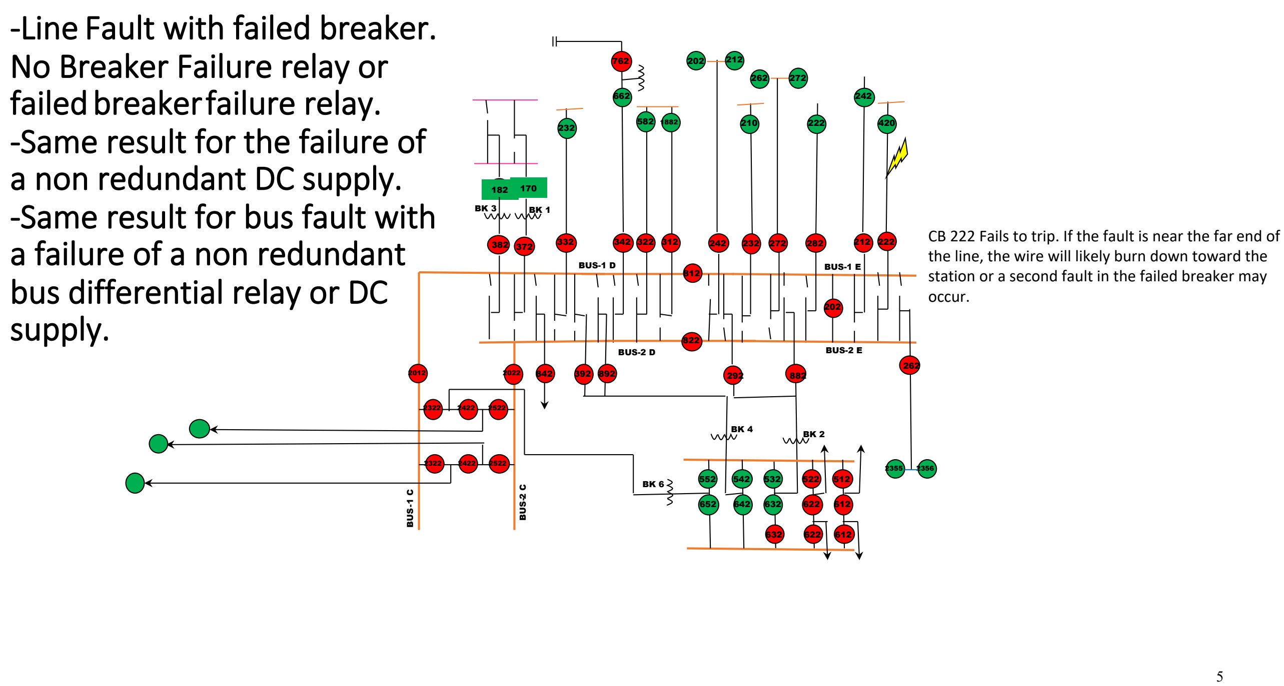

Figure 13. Line fault with failure to clear at one end due to failed DC supply or no breaker failure relay.

Delayed clearing times and breakers must be discussed with transmission planners. In some cases, their assumptions may not be correct. They may assume that bus section tie breakers or bus tie breakers will operate to limit the number of breakers that operate in some scenarios.

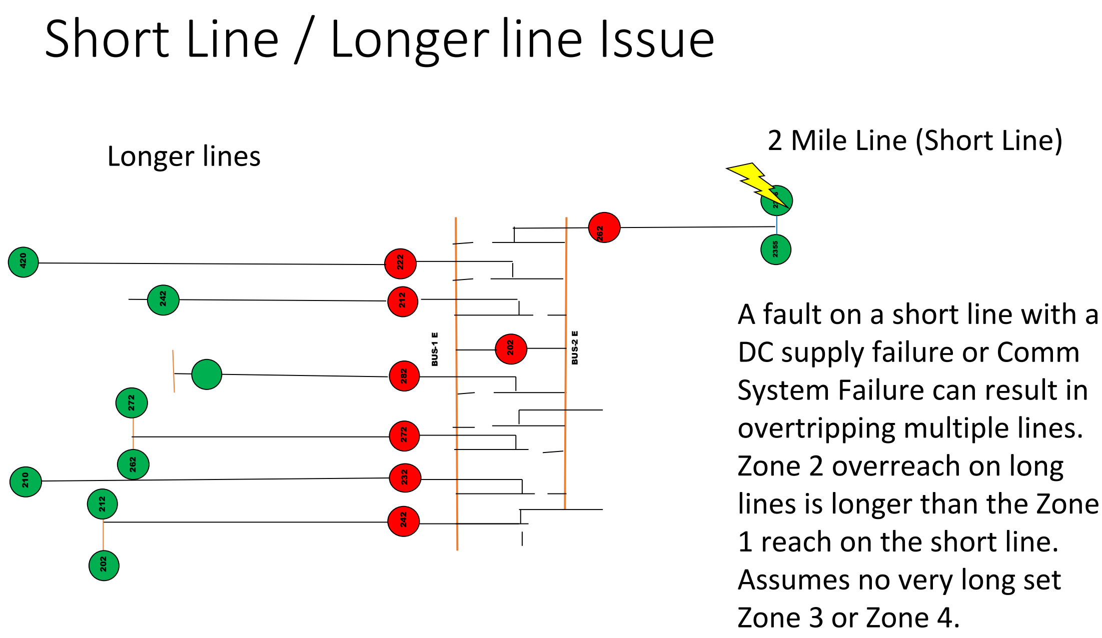

Figure 14. Faulted Short Line with Multiple Longer Lines in Area may result in multiple Overtrips.

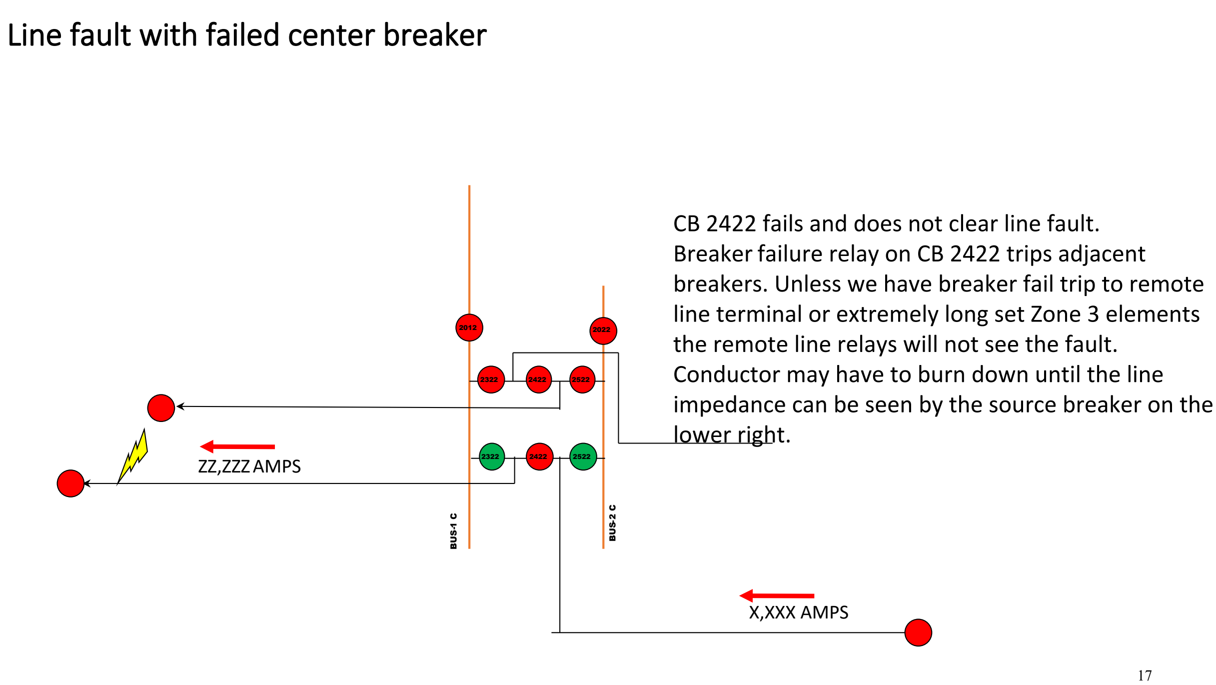

Figure 15. Failed Center Breaker in Breaker and a Half. Similar to Ring Bus Breaker Failure without Direct Transfer Trip.

TPL-001.5.1 Footnote 13 Standard Authorization Request – Submitted by PG&E

Pacific Gas and Electric Company has submitted a Standard Authorization Request to modify TPL-001.5.1 footnote 13d to allow additional monitoring and reporting options for control circuitry. This SAR was accepted and added to the existing NERC project 2022-02. At the time this paper was written the SDT is still focused on their original SAR and drafting changes to MOD-032. The authors hope that the industry and protection practitioners will support the SAR detailed below.

The NERC TPL-001-4 Reliability Standard was revised to TPL-001-5.1 (subject to Enforcement July 1, 2023), which expanded Footnote 13[1] from specific Protection System[2] relays to include communication systems, station DC supply, and control circuitry. More specifically, Footnote 13.d now applies to control circuitry from the DC supply through and including the circuit breaker trip coil. However, the footnote only provides an exclusion for a single (non-redundant) monitored and reported trip coil, but not the control circuit itself. By only excluding the trip coil and not permitting the control circuitry to be excluded, it implies that the remainder of the Protection System control circuitry is not excluded, even if it is monitored and reported. For example, it is very common to install trip circuit monitoring which monitors the control circuitry and the trip coil, but the trip coil is the only component that qualifies for the TPL-001-5.1 exclusion. The current exclusion provides no practical mechanism to be used by the Distribution Provider (DP), Generator Owner (GO), and Transmission Owner (TO) other than installing redundant control circuitry when necessary to meet Bulk Electric System (BES) performance requirements under TPL-001-5.1. Modern Protection System design includes many additional components that typically are monitored (or could become monitored and reported). Including all of the components that are monitored and reported will result in a more practical, efficient, and effective Footnote 13.d exclusion rather than adding to Protection System complexity by installing completely redundant control circuits. By modifying the Footnote 13.d exception to apply to any monitored and reported components of the control circuitry to be consistent with Protection System design and operational functionality will allow the DP, GO, and TO to achieve the required transmission performance mandated by TPL-001-5.1 in a much more efficient manner.

Purpose of SAR
The goal is to enhance the language of the Footnote 13.d exclusion to include “any non-redundant components of the control circuitry that are both monitored and reported” in addition to the current exclusion of the single trip coil. The proposed modification will reduce the burden on the DP, GO, and TO that would be required to install redundant control circuitry to ensure the BES will operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies that are studied under the TPL-001-5.1 Reliability Standard. This goal can be accomplished by modifying the exclusion language to include monitored and reported components of the control circuitry while reducing risk to BES performance by avoiding additional Protection System complexity.

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BIOGRAPHIES

Davis Erwin received his BSEE and MSEE from New Mexico State University and is a registered professional engineer in California. He has been with Pacific Gas and Electric Company since 1999 supporting 500 kV Protection Systems, Remedial Action Scheme implementation, and is presently the Director of System Protection and Automation. Prior to PG&E Davis served in the US Navy and worked for McDonnell Douglas Space Systems. He has co-authored papers or made presentations at the Western Protective Relay Conference, Georgia Tech Protection Relaying Conference, and the Texas A&M Conference for Protective Relay Engineers. Davis is one of the two continent-wide IOU members of the NERC System Protection and Control Working Group and was a member of the NERC standard drafting team for PRC-012-2 and the Glossary of Term definition of RAS. He currently serves as the Vice Chair of the WECC Remedial Action Scheme Reliability Subcommittee.

Scott Hayes received his BSEEE from California State University, Sacramento in 1985. He started his career with Pacific Gas and Electric Company in 1984 as an intern. He has held multiple positions in System Protection including supervisor, as well as Distribution Engineer, Operations Engineer, Supervising Electrical Technician, Supervising Engineer in Power Generation and is currently a Principal Protection Engineer focusing on standards, procedures, quality and compliance. Scott has previously co-authored papers or made presentations at the Western Protective Relay Conference, Georgia Tech Protection Relaying Conference, Texas A&M Conference for Protective Relay Engineers, TechCon Asia Pacific, CEATI Protection and Control Conference, NATF, CIGRE Grid of the Future, The Edison Electric Institute, and Transmission and Distribution World. Topics include Thermal Overload Relays for Intertie Lines, Data Mining Relay Event Files to Improve Protection Quality, Effects of CCVT Ferroresonance on protective relays and PG&E's Wires Down Program. Scott is a registered Professional Engineer in the state of California and has served as Chairman of the Sacramento Section of the IEEE Power Engineering Society. He has held industry leadership positions in CEATI, NATF, served on a NERC Standard Drafting Team and is a member of the IEEE PSRC D subcommittee.