

SDG&E Relay Standards – Updating Tertiary Bus and Reactor Protection

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Abstract—San Diego Gas & Electric (SDG&E) has initiated a project to upgrade and document protection schemes for the overall system. This paper discusses protection scheme design methodology and challenges for shunt reactor applications. Shunt reactors are applied for extra-high-voltage (EHV) lines to offset the voltage rise due to the Ferranti effect. Reactors may be installed directly on lines or on the tertiary bus connected to EHV transformers.

This paper discusses the possible improvements to the protection scheme design in consideration of tertiary dry-type reactors using modern relays. In addition, the paper also discusses the overall protection design as applied to the SDG&E system for reactor bank and related tertiary bus applications.

I. OVERVIEW OF SHUNT REACTOR DESIGN

Reactors are used for various applications, including fault current limiting, inrush current limit for capacitors and motors, harmonic filtering, volt-ampere reactive (VAR) compensation, neutral grounding, damping of switching transients, flicker reduction, and load balancing. This paper focuses on the protection of shunt reactors that are connected to the tertiary winding of extra-high-voltage (EHV) transformers to control system voltages during light-load conditions.

Typically, at 52 kV and above, shunt reactors are directly connected to station buses or to transmission line terminations and are grounded directly or through a neutral reactor (sometimes referred to as a four-reactor scheme). At voltages below 52 kV, reactors are commonly connected to system transformer tertiary windings and are usually ungrounded. IEEE C37.109-2006, IEEE Guide for the Protection of Shunt Reactors [1], and Fig. 1 show the characteristic configuration of shunt reactors. The three typical protection scenarios applied in the industry are:

- Bus-connected oil-immersed or dry-type reactors.
- Line-connected oil-immersed or dry-type reactors.
- Dry-type reactors connected to the tertiary winding of a transformer.

The majority of installed shunt reactors with rated voltages of 52 kV and above are in the 30 megavolt-ampere reactive (MVAR) to 300 MVAR (three-phase) range. The largest single-phase units have ratings of 125 MVAR or 375 MVAR as a three-phase group [2]. The characteristics of shunt reactors depend, to a great extent, on the design, which can be:

- Three-legged gapped iron core
- Five-legged gapped iron core
- Shell-type gapped iron core
- Coreless (air core)

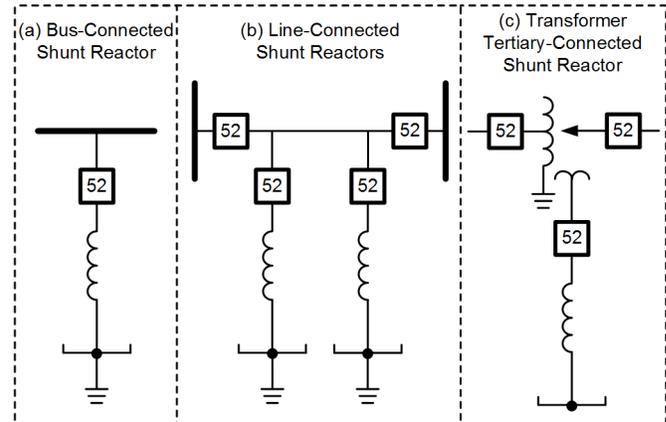


Fig. 1. Types of Shunt Reactors

Three-phase shunt reactors as a five-legged core are preferred for their robust construction and reduced vibrations. For shell and five-legged constructions, zero-sequence impedance is equal to positive-sequence impedance because a low-reluctance return path is available. For three-legged core reactors, because the flux return path is through a high-reluctance air gap, the zero-sequence reactance is lower than the positive-sequence reactance and can be 80 to 90 percent of the positive-sequence impedance. In some applications, it is a distinct advantage if the reactor has a high zero-sequence reactance [1]. In a single-pole tripping application, a neutral-grounding reactor is introduced for secondary arc extinction on single-pole tripping.

At rated voltages of 52 kV to 245 kV, reactors are commonly oil-filled and with three-legged gapped cores. However, due to new developments, some reactors with rated voltages in the range of 69 kV to 345 kV may be air-core dry-coil units.

At rated voltages of 300 kV to 500 kV, reactors are single-phase or three-phase units with three-legged, five-legged, or shell-type cores. At rated voltages of 735 kV and 765 kV, reactors are almost exclusively banks of single-phase units.

According to Section 5.1 in IEEE C37.109-2006:

Dry-type shunt reactors generally are limited to voltages...[up to 345 kV]...and can be directly connected to a transmission line [or bus] or applied on the tertiary of a transformer that is connected to the transmission line being compensated. The reactors are of the air-core (coreless) type, open to the atmosphere, suitable for indoor or outdoor application.

Natural convection of ambient air is generally used for cooling the unit by arranging the windings so as to permit free circulation of air between the layers and turns. [1]

According to the standard, because the EHV line:

...dry-type shunt reactor has no housing or shielding, a high-intensity external magnetic field is produced when the reactor is energized. Care is thus required in specifying the clearances and arrangement of the reactor units, mounting pad, station structure, and any metal enclosure around the reactor or in the proximity of the reactor. [1]

Another consideration is the effect of the magnetic fields on the impedance deviation between phases. Methods of minimizing the deviations include maintaining adequate separation or arranging the reactors in an equilateral triangle physical configuration. Deviation from the impedance values for reactors will result in a deviation from the actual rating in MVARs.

Referring to IEEE C37.109-2006, Section 5.1, for the same application:

...the primary advantages of dry-type air-core reactors, compared to oil-immersed types, include lower initial and operating costs, lower weight, lower losses, and the absence of insulating oil and its maintenance. The main limitation for the application of dry-type air-core reactors is that of connection voltage where the reactor size becomes prohibitive for higher transmission system voltages. Since these reactors do not have an iron core, there is no magnetizing inrush current when the reactor is energized. [1]

Because the amount of reactive power compensation needed in a system varies, shunt reactors may be switched daily. Thus, shunt reactors will experience a large number of switching transients and transient overvoltage. The behavior of these overvoltages depends on many factors, such as the following:

- Circuit connection (wye or delta).
- Method of neutral grounding.
- Rated MVAR of the reactor.
- Construction of reactors (air core, iron core, three legs, or five legs).
- Type of connection to the system (direct or tertiary winding).
- Type and ratings of circuit breakers.
- Neighboring equipment characteristics.

Breaker damage cases have been observed in the past that were the result of severe overvoltages, particularly when reactors were disconnected. In addition, there have been reported cases of delayed current zero-crossing during switching of shunt compensated lines [3] [4]. If the line breaker

attempted to open immediately after line energization while the line current still had a direct current (dc) offset, the breaker would fail due to no current zero-crossing. A detailed analysis during equipment sizing and surge arrester selection will eliminate some of these challenges.

II. SHUNT REACTOR PROTECTION AND DESIGN

The following two basic shunt reactor configurations are considered in this paper:

- Dry-type air-core, ungrounded wye, connected to the tertiary of a power transformer [1] [2].
- Oil-immersed, wye-connected, with a solidly grounded or reactance-grounded neutral, connected to the transmission system. Neutral-grounding reactors may also be applied for a single-pole tripping application [1] [2] [4].

The focus of this paper is on tertiary-connected, dry-type air-core reactors. Therefore, transmission applications will not be discussed further.

A. Dry-Type Reactor Faults and Protection

Three types of faults occur in dry-type reactor installations [1] [5]:

- Phase-to-phase faults on the tertiary busbar, resulting in a high-magnitude phase current.
- Phase-to-ground faults on the tertiary busbar, resulting in a low-magnitude ground current, which is dependent on the grounding of the tertiary bus.
- Turn-to-turn faults within the reactor bank, resulting in a very small change in phase current.

Phase-to-phase faults are a low-probability fault for dry-type reactors because the reactors are single-phase units with relatively wide spacing between phases. The main cause of phase-to-phase faults is when arcing from a failed reactor is not detected soon enough and the fault ionization moves up into the tertiary busbar, resulting in a phase-to-phase fault. Because dry-type reactors are mounted on insulators, which provide standard clearance and insulation to ground, direct winding-to-ground faults are also a low probability and are only produced when the neutral insulation is bridged, for example, by an animal. The damage done by a winding-to-ground fault is determined by the system grounding.

Turn-to-turn insulation failures in dry-type reactors begin as tracking from insulation deterioration or contamination (e.g., bird droppings, environmental). Once the arc is initiated, if not detected quickly, these failures cascade to the entire winding because of the interaction of the arc with the magnetic field of the reactor.

Major fault protection for dry-type reactors can be achieved through overcurrent, differential, or negative-sequence relaying schemes, or by a combination of these relaying schemes. Protection for low-level, turn-to-turn faults can be provided by a voltage-unbalance relay scheme connected at the neutral with compensation for the inherent unbalance of system voltages and the tolerances of the reactor. In addition, negative-sequence overcurrent protection can also be used to detect turn-to-turn faults.

The focus of this paper is on tertiary-connected, dry-type air-core reactors. Therefore, transmission applications will not be discussed further.

B. Tertiary-Connected, Dry-Type Air-Core Reactor Protection

Fig. 2 shows the typical connection for dry-type reactors. Reactor breakers can be located on either the line side or neutral side. In case the fault current is high, which is normally the situation, reactor breakers are located on the neutral side [1] [2]. Refer to Section III and Section IV for discussions on the challenges and proposed design details.

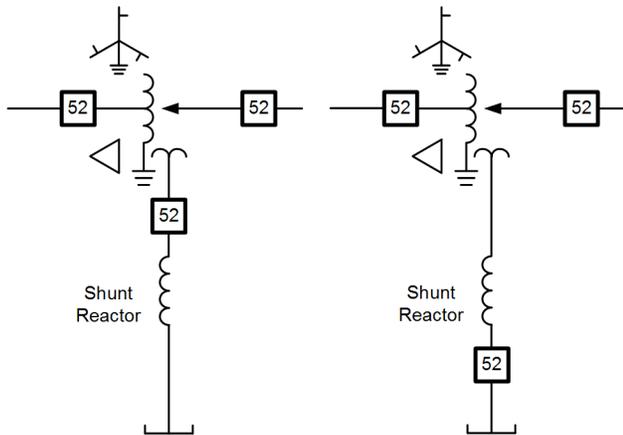


Fig. 2. Typical Configuration for Dry-Type Shunt

According to IEEE C37.109, typical protection devices applied to tertiary-connected, dry-type reactors are the following:

- Instantaneous overcurrent protection (50)
- Time-delayed overcurrent protection (51)
- Negative-sequence protection (46)
- Ground overvoltage protection (59N)
- Special schemes for turn-to-turn faults

In addition, the following protection functions may also apply:

- Phase differential protection, which can be the transformer differential (87T) when the shunt reactor is included in the power transformer or a separate reactor phase differential protection.
- Breaker failure protection (50BF).

Fig. 3 shows the typical protection for dry-type tertiary shunt reactors. The transformer differential zone includes the shunt reactor protection. For tertiary bus phase-to-phase faults, the differential relay will operate to open the transformer breakers. Note that the differential relay will not be sensitive to all faults; therefore, additional protection is required [1] [2]. Fig. 3 shows the reactor breaker on the tertiary bus side of the reactor; however, all remaining figures will show the breaker on the neutral side of the reactor, which is consistent with installations in the San Diego Gas & Electric (SDG&E) system.

Ground overvoltage protection is an inexpensive, simple, and reliable device for the detection of phase-to-ground faults in the entire tertiary system. However, the protection cannot locate the ground fault and thus will not differentiate between ground faults on the shunt reactor or on other parts of the tertiary system. Because the tertiary system is ungrounded or high-resistance grounded, the resulting ground fault current will be of low magnitude [5]. Consistent with many utilities, SDG&E uses the practice to alarm and not to trip for this abnormal condition [5].

Sometimes grounding transformers are used on tertiary systems to limit the potential rise against ground faults. To limit the phase-to-ground current to acceptable, recommended levels, resistors that are connected on the secondary side of grounding transformers are used. During phase-to-ground faults, sufficient zero-sequence voltage (3V₀) quantities across the resistor will serve the ground overvoltage protection (59N) function.

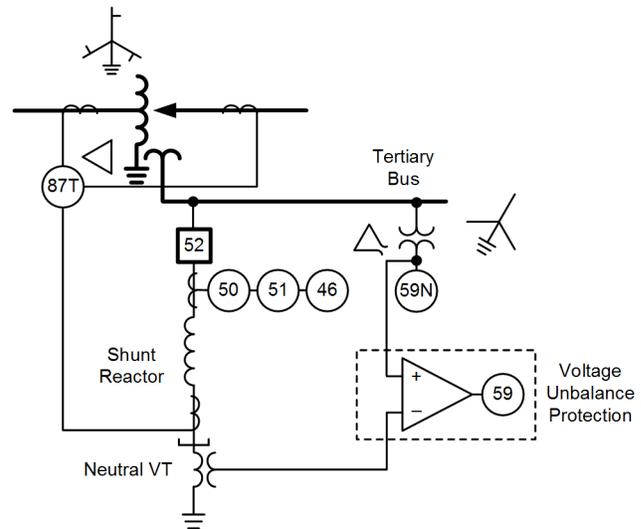


Fig. 3. Dry-Type Shunt Reactor (Typical Protection)

Generally, it is recommended that the primary ground fault current caused by the resistor should be equal to, or higher than, the capacitive ground fault currents in the system. This will reduce the transient overvoltages that may occur after restrikes in the fault arc to safe levels. Also, grounding transformers with a grounding resistor can be applied as an alternative way to achieve high-resistance grounding of the system (see Fig. 4). Recently, a major utility witnessed a challenge to tertiary bus and reactor protection, and experienced a near miss case during a phase-to-phase fault, involving ground on the neutral side of the reactor when the reactor breaker was open. This fault condition is a special challenge because the fault current is limited by the reactor impedance.

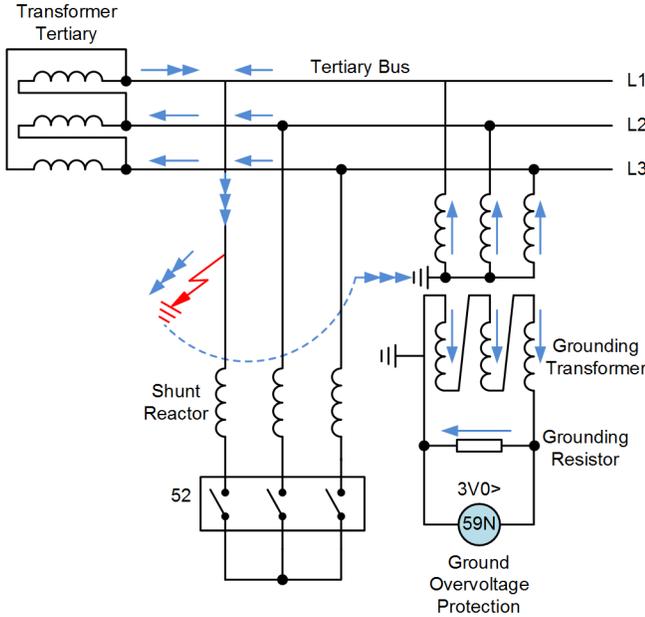


Fig. 4. Dry-Type Shunt Reactor (Ground Overvoltage)

III. SDG&E SYSTEM OVERVIEW AND SHUNT REACTOR STANDARDS

SDG&E (the utility) operates a 500 kV eastern interconnection to Arizona Public Service (APS) at the Imperial Valley 500/230 kV substation. There are two 500 kV lines from Imperial Valley into the San Diego area load. In addition, SDG&E operates a 230 kV northern interconnection to Southern California Edison (SCE) at the San Onofre 230 kV substation. There are a total of five utility 230 kV lines connected at San Onofre. Under normal operation, the flows are east to west at Imperial Valley and south to north at San Onofre. Depending on system imports at Imperial Valley and through-flow at San Onofre, reactive sources are needed to allow system operators to control system voltage.

Switched reactors can provide a benefit in maintaining system voltage by mitigating the high charging current associated with 500 kV transmission lines. In addition, SDG&E discovered an increased operating need for reactive power control after placing into service new 230 kV transmission lines, with significant lengths of 230 kV underground cable. With the new lines in service, it became more difficult for the system operators to hold the transmission system voltage down during minimum load periods. A new reactor switching capability was required to mitigate the high reactive current due to the 230 kV cable additions and allow adequate system voltage control throughout all operating scenarios.

The utility applied a mix of reactive sources, including transmission capacitors (230 kV, 138 kV, and 69 kV), synchronous condensers (two units at 500 kV and five units at 230 kV), and reactors. There are two 500 kV oil-filled line reactors (126 MVAR each); four 69 kV bus-connected, air-core reactor banks (50 MVAR each); four 12 kV bus-connected, air-core reactor banks (7.2 MVAR each); and tertiary-connected reactor banks.

A. Current Shunt Reactor Protection Design

SDG&E operates five of its 500/230/12 kV autotransformer banks with 12 kV air-core reactors connected to the tertiary bus. Four 45 MVAR reactor banks are connected from each of the bank's tertiary buses. These reactors are switched by 12 kV vacuum breakers on the neutral side of the reactors. The tertiary reactors provide an operational benefit by allowing the system operators to fine-tune the reactive power mix to control system voltage. Switching 45 MVAR increments provides better control than the 126 MVAR increments provided by the 500 kV line-connected reactors.

Similar to most utilities, SDG&E originally protected the 12 kV tertiary bus in these substations as a part of the overall bank differential protection scheme, as shown in Fig. 3. In addition, backup overcurrent protection (electromechanical) was provided for tertiary fault protection. Protection for shorted turns on the tertiary reactors was provided by electronic relays, which compared the measured voltages from a wye-broken-delta potential transformer (PT) and individual single-phase PTs connected at the neutral end of the reactors. As shown in (1), the ground detector voltage is divided by three and the measured neutral voltage is subtracted.

$$V_{OPNn} = \frac{V_{GD}}{3} - V_{Nn} \quad (1)$$

where:

V_{OPNn} is the operating voltage for reactor n .

V_{GD} is the ground detector voltage.

V_{Nn} is the neutral voltage for reactor n .

This calculation is performed for each of the four reactors.

Under normal conditions, the operating voltage should be zero. If there is a tertiary bus and low-resistance ground, the $V_{GD}/3$ and V_{Nn} voltages are equal, yielding an operating voltage of zero. If there is a finite operating voltage, it is an indication that the tertiary reactor neutral voltage has shifted due to shorted turns in the protected reactor. The relay logic was set to provide an alarm output for small voltage variations and a reactor breaker trip was initiated for higher voltage variations.

After experiencing a failed vacuum bottle with a resultant fire at a tertiary breaker and hearing about tertiary bus events at other utilities, SDG&E investigated opportunities to upgrade the transformer and tertiary bus protection systems. The utility decided that it would be advantageous to provide discrete protection for the tertiary bus and reactor, separate from the main transformer differential protection (refer to Fig. 5). Details of the current transformer (CT) connection for the utility's Upgrade 1 are shown in Fig. 6. Therefore, following a transformer trip due to a tertiary bus issue, system operators would be able to identify that the trip was because of a condition external to the protected transformer. In addition, it would then be possible to provide more sensitive differential protection of the tertiary bus and connected reactors because lower tap values are used for the protection of the 180 MVA system ($4 \cdot 45$ MVAR) as compared to the 1,120 MVA rating of the connected transformer bank.

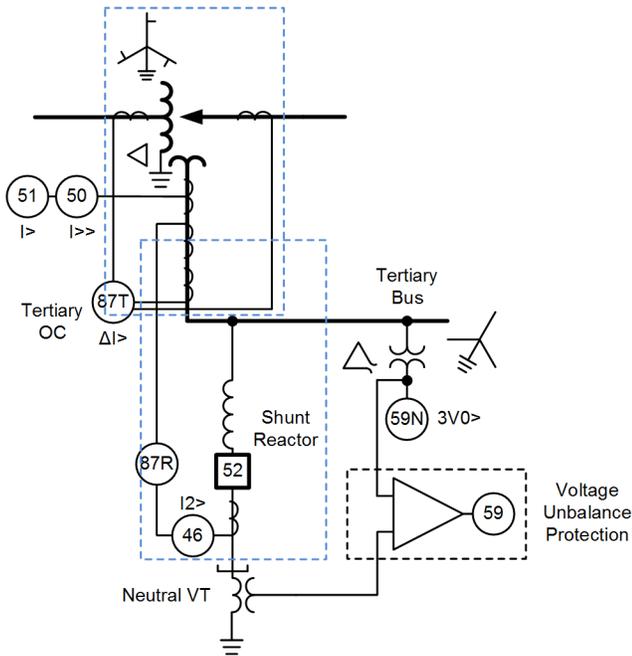


Fig. 5. SDG&E Using Separate Zones for Transformer and Reactor

As part of a large construction project in 2004 at the Miguel 500/230/138/69 kV substation, SDG&E redesigned the bank differential protection to provide separate differential zones for the 500/230/12 kV transformer and the 12 kV tertiary bus and reactor.

Tertiary overcurrent protection was provided by two microprocessor relays. This new protection scheme, which was upgraded in 2004 (Upgrade 1), is shown in Fig. 6. The new tertiary bus differential relay issued trip outputs to the existing transformer trip and lockout (T&LO) relays; therefore, no new tripping relays were added.

The Upgrade 1 project design used the transformer tertiary bushing CTs as the “exit” boundary for the redundant transformer differential relays. The new tertiary bus differential relay used transformer tertiary bushing CTs, along with the neutral-connected reactor breaker CTs. With the ability to monitor the reactor CTs, the utility was able to apply sensitive negative-sequence overcurrent protection to provide a redundant means of detecting shorted turns in the reactors. The differential relay included four sets of input currents in addition to five sets of currents in the zone. The tertiary bushing CTs were used as Winding 1; whereas, Reactor Breaker 1 and two CTs were paralleled for Winding 2. Reactor Breaker 3 and four CTs were used for Windings 3 and 4, respectively. The negative-sequence outputs functioned to trip the reactor breakers. For a Winding 2 negative-sequence overcurrent pickup, Reactor Breaker 1 is tripped without delay. If the negative-sequence overcurrent pickup is still present, Reactor Breaker 2 is tripped on time delay. Overall, this scheme used seven relays for tertiary reactor and bus protection.

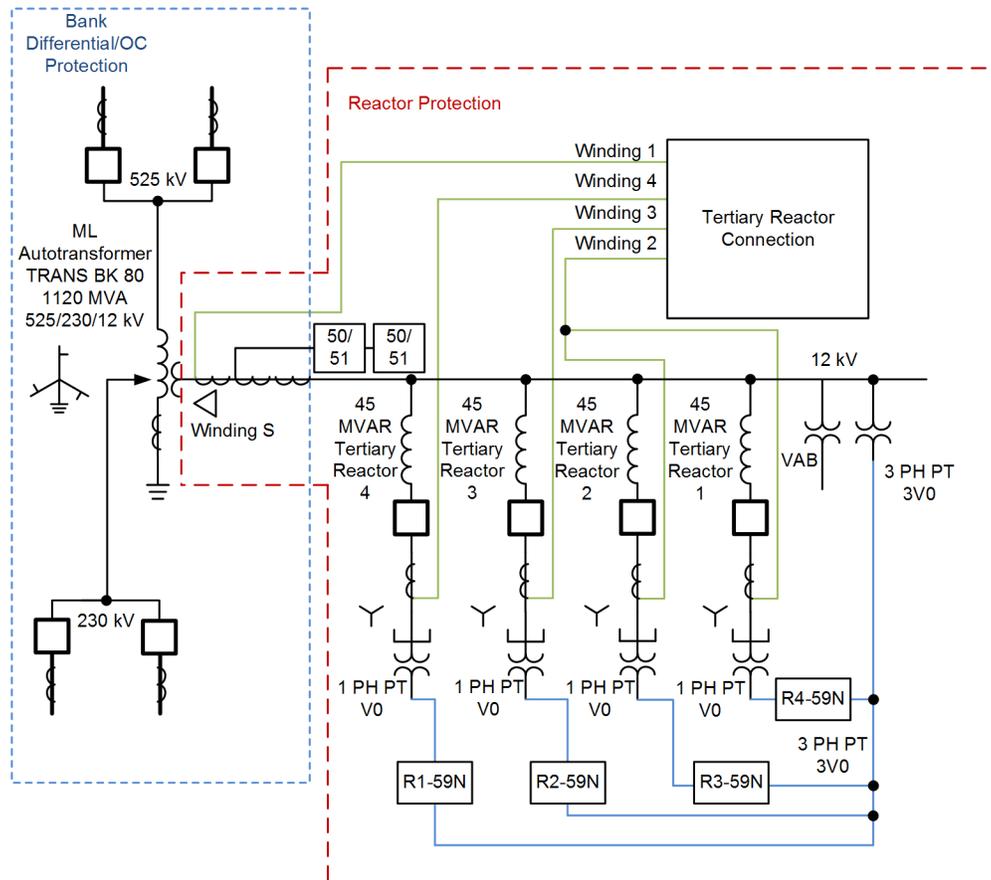


Fig. 6. Transformer and Tertiary Reactor (Upgrade 1, 2004)

For the primary reactor shorted turn protection, the utility employed individual microprocessor relays to detect voltage unbalance, which was due to neutral shift tripping the reactor breakers. These relays provided a null voltage for the original in-service testing to account for any initial offset voltage.

One of the advantages of this scheme was the ability to perform logic in the new differential relay to deal with varying voltage and current data. For example, the normal practice for the utility in responding to a tertiary bus ground detector output is to alarm. However, if there is a sustained negative-sequence overcurrent output along with a ground detector output, this indicates an abnormal tertiary bus contact event. Under this condition a transformer bank trip output is required to clear the fault. In addition, there is the ability to provide breaker failure for the tertiary reactor breakers. These protection logic additions are shown in Fig. 7 and will be discussed further in Section IV.

SDG&E uses two transformer differential relays and one overcurrent relay as the standard package for transmission autotransformers. One high-voltage (HV) winding phase (50P) and ground instantaneous (50G), and one time overcurrent (51P) are enabled. The 50P/50G is selected higher than 150 percent of the low-voltage (LV) fault and 150 percent of the tertiary fault. The HV 51P pickup is selected higher than 115 percent of the emergency rating and 150 percent of full-load amperes, with an IEEE Inverse U2 curve and a time delay (TD) to meet the tripping time requirement of approximately 0.5 seconds for LV faults. The HV 51G pickup is selected around 33 percent of the 51P with an IEEE Very Inverse U3 curve and a TD to operate in approximately 0.5 seconds for an LV fault. The utility also uses one level of 51P and 51G on the LV side of the transformer. There is no inverse overcurrent (IOC) element enabled on the LV winding. Because the tertiary is ungrounded, the ground overcurrent coordination between the transformer and the reactor is not an issue. However, the 51P should be coordinated. For reactor tertiary phase faults, 51P on the tertiary reactor is coordinated with 51P on the HV and LV windings.

B. Future Shunt Reactor Protection Design

As new multifunctional relays with custom programming have become available, the utility is reporting on the results of the investigation and the next steps in tertiary bus and reactor protection. As shown in Fig. 8, all protection functions previously described can be performed redundantly by two microprocessor relays. The new relays include five sets of CT inputs and six voltage inputs for the bus broken-delta 3V0 signal, as well as four reactor neutral PTs and one single-phase voltage input. The protection algorithms for the voltage-

unbalance protection can be written into the relay settings and the custom logic can be provided for overall bank tripping and breaker failure detection. The sensitive negative-sequence overcurrent protection is also provided, as discussed in the following paragraphs. The individual reactor inductances, and therefore impedances, can be carefully controlled to values within 1 percent. For example, on a large SDG&E project that included a total of eight tertiary reactors (24 single-phase reactors), a review of the test reports indicated that the maximum impedance variations were ± 1 percent. Therefore, the ambient neutral voltage and negative-sequence currents should normally have been at a very-low level. This allowed the use of sensitive settings.

One great advantage in providing sensitive turn-to-turn protection for dry-type tertiary reactors is that the individual tertiary reactor banks are generally not a critical element for system operation. The reactor bank voltage-unbalance and negative-sequence overcurrent settings can be selected as sensitive without any concern for security.

Fig. 8 illustrates the details of the protection connections in the new multifunction relays at the utility. Because of the capability of the advanced relay, custom logic calculations, as previously mentioned, are easy to accomplish. Table I lists the details of the CT/PT connections in the relays. Each relay is connected via five three-phase CTs and six single-phase voltages. As shown, there are separate CT winding inputs for each reactor breaker. This provides an advantage over the previous design because discrete reactor breaker trip outputs can be provided from the negative-sequence overcurrent elements associated with each CT winding input.

TABLE I
RELAY CONNECTION AND APPLICATION

Winding/Connection	Device	Comments
Winding S	12 kV bus	3-phase CT, delta
Winding T	Reactor 1	3-phase CT, wye
Winding U	Reactor 2	3-phase CT, wye
Winding W	Reactor 3	3-phase CT, wye
Winding X	Reactor 4	3-phase CT, wye
VAV	12 kV ground detection	3-phase PT = 3V0
VBV	Reactor 1	1-phase PT = V0
VCV	Reactor 2	1-phase PT = V0
VAZ	Reactor 3	1-phase PT = V0
VBZ	Reactor 4	1-phase PT = V0
VCZ	VAB 12 kV bus	Voltage reference

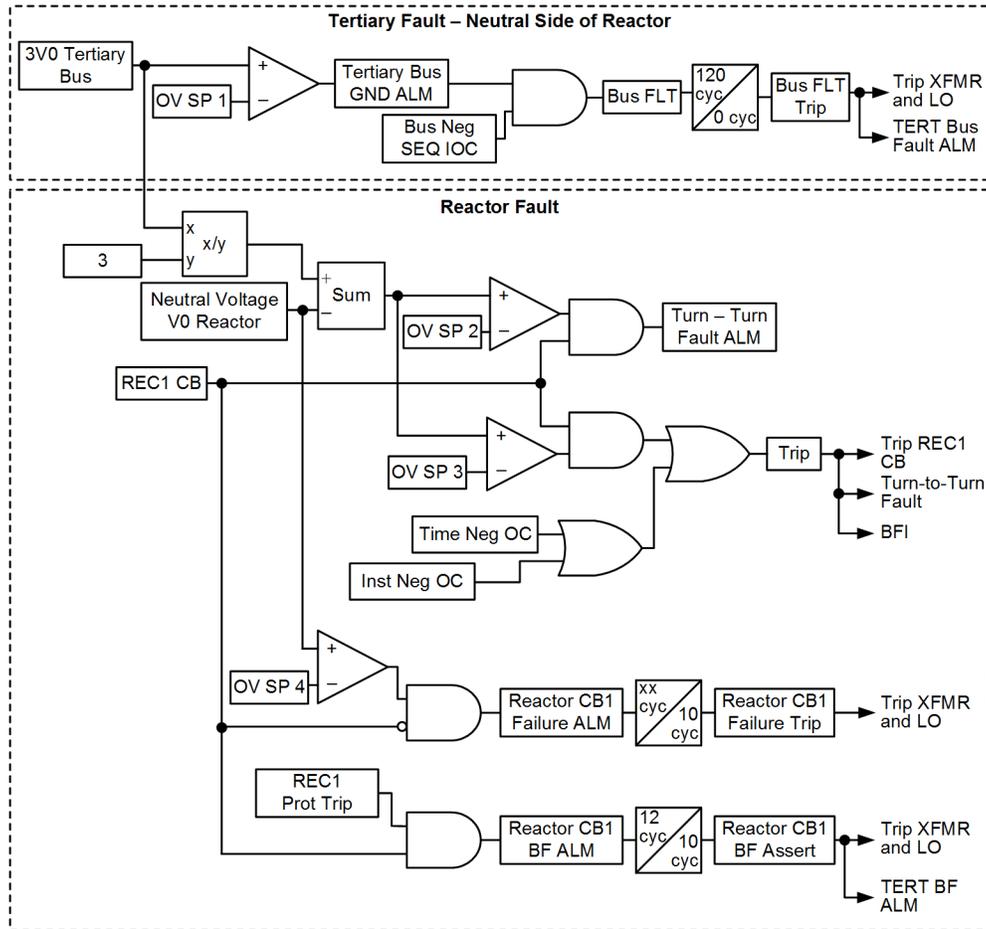


Fig. 7. Tertiary Reactor and Bus Protection Logic Diagram

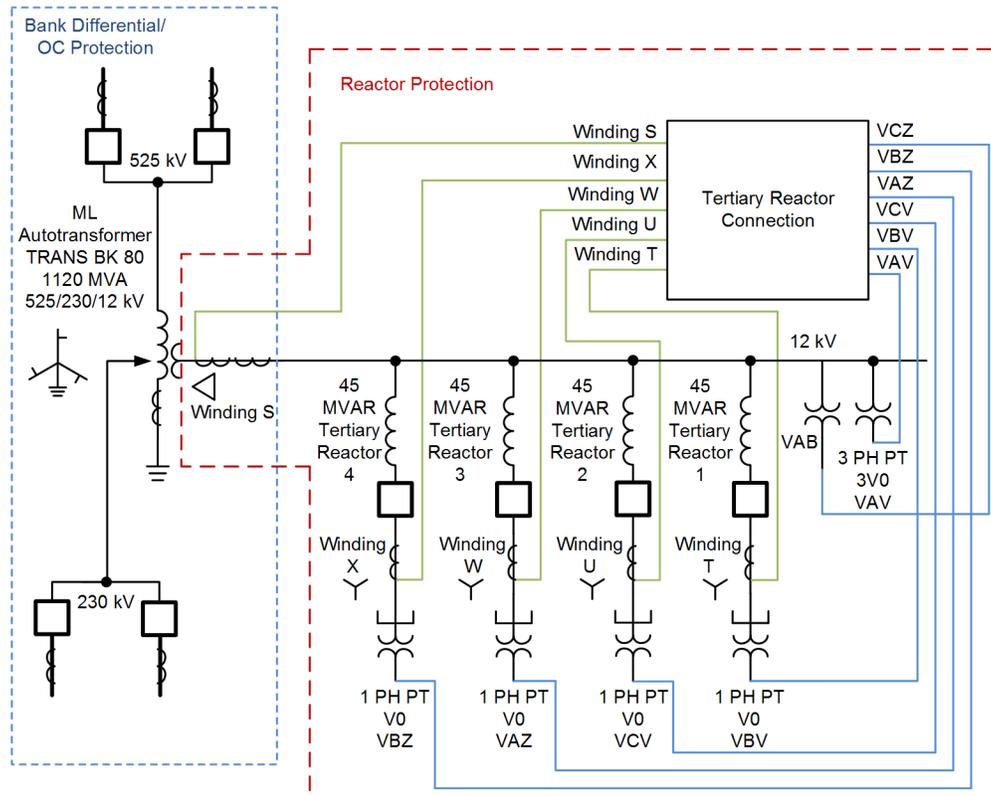


Fig. 8. SDG&E 2019 Upgrade Project: Tertiary Shunt Protection

IV. DESIGN DETAILS AND LOGIC DISCUSSION

A. Protection Logic and Front-Panel Design

The reactor bank protection functions with the calculated setting values are shown in the following paragraphs.

Table II defines the various operating conditions for detection by the protective relays, where V_N is the neutral shift voltage for each reactor and V_{GD} is the tertiary bus ground voltage, measured using broken-delta voltage transformer (VT), and is equal to $3V_0$.

TABLE II
SET-POINT SELECTION LOGIC

System Condition	$V_{GD}/3$	V_N	$(V_{GD}/3 - V_N)$	50Q	Summary
Reactor CB closed, 3-phase load	0	0	0	0	None
Tertiary bus ground, reactor CB closed	69 V	69 V	0	0	Alarm – “Tertiary Bus Ground” (based on V_{GD})
Shorted reactor turns, CB closed	≈ 0	> 0	> 0		Alarm – “Turn-turn Failure,” trip reactor CB (based on $(V_{GD}/3 - V_N)$ or 50Q, initiate breaker failure
CB open, one pole closed (failed vacuum bottle)	0	69 V	-69 V	0	Alarm – “Reactor CB Failure,” followed by transformer T&LO trip

For example, for normal operating conditions:

$$V_N = V_0 = 0 \text{ volts}$$

However, for the tertiary ground:

$$V_N = 69 \text{ volts}$$

$$V_{GD} = 3V_0 \text{ (broken-delta voltage at bus)} = 3 \cdot 69 = 207 \text{ volts}$$

When a ground fault occurs and the reactor breaker is open, V_N will be zero for the reactor that is not in service because the reactor breaker is located on the neutral side. Custom logic is programmed in the relay to detect the condition when one pole of the vacuum reactor circuit breaker (CB) fails to open or close. The logic is based on the V_N and $V_{GD}/3 - V_N$ calculations. For this condition, because there is no bus ground, $V_{GD} = 0$. Hence, V_N and $V_{GD}/3 - V_N$ will record 69 V and -69 V, respectively.

Fig. 7 displays the logic for one reactor and similar logic, which is applicable to all four reactors connected to the tertiary bus. The logic uses the bus PT voltage, $3V_0$; the reactor neutral voltage, V_0 ; and the reactor breaker status, in addition to the negative-sequence current to determine the various faults and locations. Breaker failure protection is also designed in the

reactors to trip the transformer lockout relays in case the reactor breakers fail to operate.

Fig. 9 shows the details of the front-panel light-emitting diodes (LEDs). The front panel shows the status of all reactor breakers, turn-to-turn faults, and breaker failures. As shown in the figure, an LED indication is also available for tertiary bus ground.

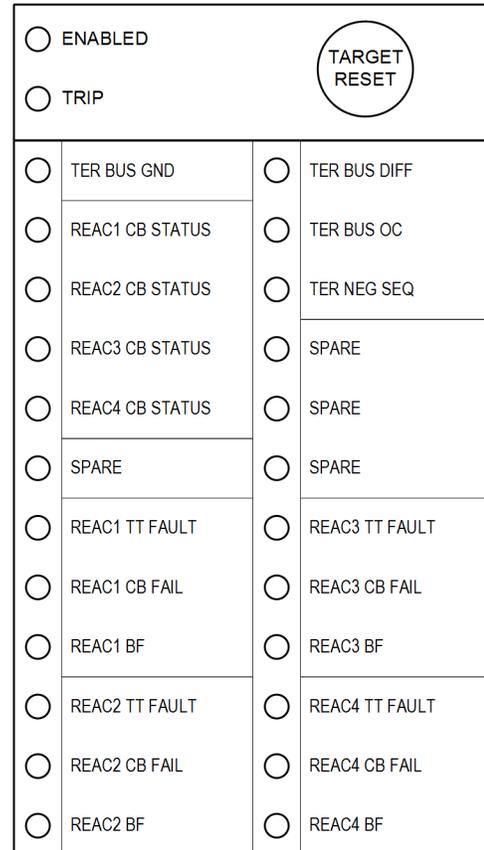


Fig. 9. Tertiary Bus and Reactor Protection (Front Panel)

B. Set-Point Selection and Coordination

The following protection elements are enabled in the relay [6] [7] [8] [9]:

- Differential (87P).
- Phase overcurrent (OC) (50P/51P) on the bank tertiary CT winding.
- Negative-sequence (50/51Q) on the bank tertiary CT winding.
- Turn-to-turn (50/51Q) on the reactor breaker CTs.
- V_0 and $3V_0$ (59 ground detection, custom logic).

1) Differential (87P)

For this application, an adaptive slope differential protection scheme is selected. The slope settings prevent misoperation due to false differential currents on the CT saturation during high-grade through-faults and during normal operation. A reactor does not experience a high-grade through-fault current because a fault on the line causes voltage depression, and the current through the reactor is relatively less than the rated current. Therefore, the slope setting is not as significant as it is in transformers or in bus differential applications; hence, the

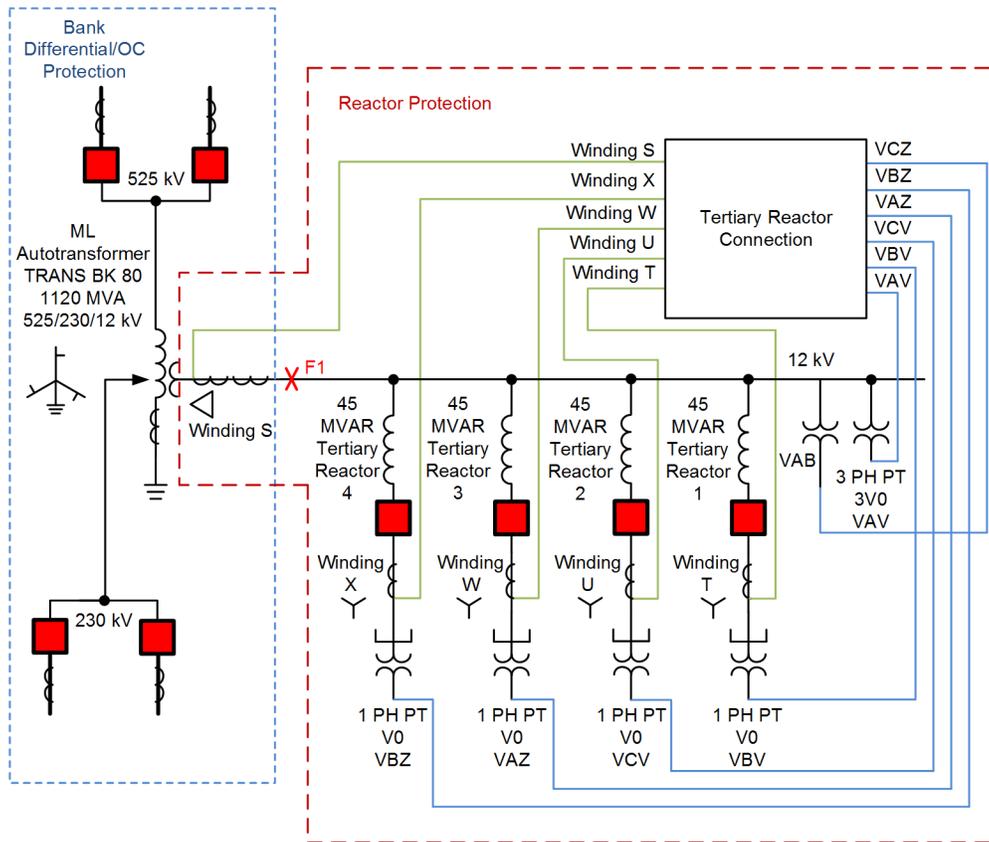


Fig. 10. Tertiary Bus Phase-to-Phase Fault Location F1

Slope 1 and Slope 2 settings can remain at the relay default values. Typical pickup settings are in the range of 0.2 to 1.0 per unit of rated current. For this application, a pickup of 0.20 per unit is selected. The O87P element is set to allow detection of phase-to-phase faults on the circuit breaker side of the reactors (e.g., a fault at the reactor breaker bushings when the breaker is open, as shown in Fig. 10). As previously discussed, this is a challenging protection issue. The fault current is limited by the reactor impedances, resulting in phase currents of 0.86 times the normal load current, which equals 1,875 amperes. A setting of O87P = 0.20 per unit, is equivalent to a pickup setting of:

$$0.20 \cdot 8,660 \text{ amperes} = 1,732 \text{ amperes}$$

Hence, the differential protection will operate for this fault. Slope 1 and Slope 2 are selected at settings of 15 percent and 50 percent, respectively. The unrestrained element, U87P, is turned off because the 50P element is selected.

2) 50P/51P Element

The instantaneous element (50P) is used to protect tertiary bus phase-to-phase faults on the source side of the reactors, as shown in Fig. 10. The pickup is selected above the nominal current (I_{NOM}) with a margin. The pickup is proposed at the current at 110 percent of the voltage, with a margin of 125 percent:

$$\begin{aligned} I_{\text{NOM}} (4 \cdot 45 \text{ MVAR reactors}) &= 4 \cdot 2,165 \text{ amperes} \\ &= 8,660 \text{ amperes} \\ 50P &= 1.1 \cdot 1.25 \cdot 8,660 \approx 11,900 \text{ amperes} \end{aligned}$$

Because it is not possible to set 51P, it is disabled for this application. The coordination on the transformer overcurrent relays must be verified with the 50P elements on tertiary windings.

3) Negative-Sequence Overcurrent (Bank Tertiary CTs)

This element (50/51Q) is set to detect phase-to-phase faults on the circuit breaker side of the reactors (e.g., a fault at the reactor breaker bushings when the breaker is open, as shown in Fig. 11). As previously discussed, this is a challenging protection issue. As discussed in Subsection 1, the fault current is limited by the reactor impedances, resulting in phase currents of 0.86 times the normal load current, which equals 1,875 amperes. The calculated 3I2 value equals 3,246 amperes. The 50Q setting is selected at 40 percent of this value. Therefore, a 50Q setting is selected:

$$0.40 \cdot 3,264 \text{ amperes} \approx 1,300 \text{ amperes}$$

51Q is selected at:

$$0.20 \cdot 3,264 \text{ amperes} = 650 \text{ amperes}$$

with an IEEE Inverse U2 curve and a TD to operate in 0.5 seconds for phase-to-phase faults.

4) Negative-Sequence Overcurrent (Reactor Breaker CTs)

With the reactor breaker at the neutral end, a reactor turn-to-turn fault is the only fault that tripping this breaker can clear. Once the voltage across the turns is removed, because the end is now floating, the arc should extinguish. Every other type of

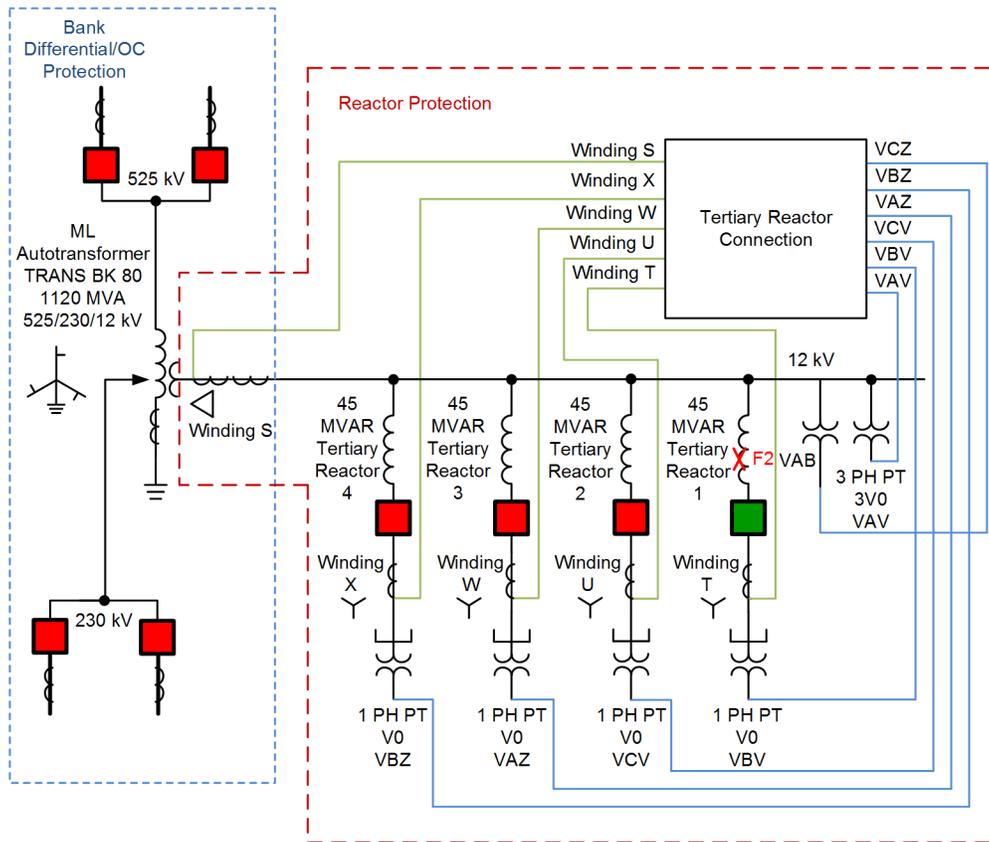


Fig. 11. Tertiary Reactor Phase-to-Phase Fault Location F2 (Reactor and Open Reactor Breaker)

fault has to be cleared by tripping the whole transformer. If the turn-to-turn fault is not cleared, it can evolve into a high-current tertiary bus fault that could fail the transformer.

A short circuit between winding turns of the same phase (turn-to-turn fault) will result in decreased apparent phase impedance. The inductance is proportional to the number of turns; hence, for a short circuit involving 5 percent of turns, the apparent impedance of the reactor is approximately:

$$(0.95)^2 \cdot X_L = 0.9 X_L \quad (2)$$

For a 20 percent short circuit, the inductance will vary, however:

$$(0.80)^2 \cdot X_L = 0.64 X_L \quad (3)$$

The impedance variation will result in a neutral voltage shift and negative-sequence current. Supplementing the neutral voltage-unbalance protection, negative-sequence overcurrent protection can also be used. Considering the maximum system unbalance, a negative-sequence overcurrent of 5 to 10 percent can be selected, with some amount of delay. The 50Q element is set for a pickup value of 150 amperes primary, which would be initiated by an approximately 2.6 percent turn-to-turn fault, with a 2-second delay.

Turn-to-turn protection using the 87Q element, which is very reliable for transformers, cannot be applied for reactors [9] [10]. The transformer 87Q element is based on Ampere's law of turn balance. Protection for shunt reactors is based on Kirchoff's current law, instead of ampere-turns (AT) balance,

because of the absence of a second winding. In reactors, for turn-to-turn short circuits, the current entering and leaving is the same. Hence, for reactors, both 87P and 87Q cannot detect turn-to-turn faults; however, negative-sequence overcurrent will see turn-to-turn faults.

5) SDG&E New Reactor Protection Standards

The proposed new standards for reactor protection schemes can provide multiple protection elements for detection, including:

- One differential zone for the overall tertiary bus protection.
- One level of tertiary bushing CT phase overcurrent protection, coordinated with the transformer overcurrent protection.
- One level of tertiary bushing CT negative-sequence overcurrent protection to detect phase-to-phase faults between the reactor and the open reactor breaker. In case of sustained ground detection with negative-sequence overcurrent, the transformer breakers are operated.
- One level of neutral overvoltage to detect tertiary bus ground conditions.
- Each tertiary 45 MVAR reactor is programmed to detect turn-to-turn faults, using neutral voltage shift and negative-sequence overcurrent functions.
- Breaker failure protection is programmed for the reactor breakers to provide transformer trip outputs if a reactor breaker fails to operate for a protective trip.

In addition to improving fault detection using negative-sequence overcurrent and isolating the transformer when required, the new scheme provides selectivity and sensitivity. Migrating all protection functions for tertiary bus and reactor protection into two modern relays provides the additional benefits of easy maintenance and troubleshooting, as well as the benefits of oscillography, a front display, and Sequence of Events data.

V. CONCLUSION

Dry-type tertiary-connected shunt reactors are a critical component for the grid operation. This paper discusses the SDG&E protection design and upgrade using modern relays and their own protection standards for tertiary bus and shunt reactors. Custom logic programming in the modern relays simplified the protection and design. Using the capabilities of modern relays, the utility was able to reduce the number of relays from seven to two, which included additional redundancy and improved functionality. The new relays offered adaptive slope differential protection that provided protection sensitivity improvements. One important improvement was using negative-sequence overcurrent in combination with the ground detection scheme to protect for faults between the reactor and the open reactor breaker. Because the reactor breaker is located on the neutral side of the reactor, faults between the reactor and breaker would fail to clear by only opening the reactor breakers. Therefore, the utility is proposing that for these reactor faults, the transformer zone breakers must be operated.

The paper also presents a discussion regarding the various detection methods, logic details, sensitivity, and set-point selection.

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VII. BIOGRAPHIES

Bill Cook is retired from engineering positions at San Diego Gas & Electric (SDG&E). Bill started his career at SDG&E in 1976 as an engineer in the Substation and System Protection groups. He moved to the manager position in System Protection and Control Engineering in 1997. In 2014, he moved to an engineering position in Grid Operations. Bill earned his B.S.E.E. from California Polytechnic State University in San Luis Obispo. He is a registered professional engineer in California and a member of IEEE. He was a member of the Western Electricity Coordinating Council (WECC) Remedial Action Scheme Reliability Subcommittee (RASRS) from 1999 to his retirement date in December 2018.

Michael J. Thompson received his B.S., magna cum laude, from Bradley University in 1981 and an M.B.A. from Eastern Illinois University in 1991. Upon graduating, he served nearly 15 years at Central Illinois Public Service (now AMEREN). Prior to joining Schweitzer Engineering Laboratories, Inc. (SEL) in 2001, he worked at Basler Electric. He is presently a Fellow Engineer with SEL Engineering Services, Inc. He is a senior member of the IEEE, officer of the IEEE Power & Energy Society (PES) Power System Relaying and Control Committee (PSRCC), past chairman of the Substation Protection Subcommittee of the PSRCC, and received the Standards Medallion from the IEEE Standards Association in 2016. Michael is a registered professional engineer in six jurisdictions, was a contributor to the reference book, *Modern Solutions for the Protection, Control, and Monitoring of Electric Power Systems*, has published numerous technical papers and magazine articles, and holds three patents associated with power system protection and control.

Kamal Garg received his M.S.E.E. from Florida International University and India Institute of Technology, Roorkee, India, and his B.S.E.E. from Kamla Nehru Institute of Technology, Avadh University, India. Kamal worked for POWERGRID India and Black & Veatch for several years at various positions before joining Schweitzer Engineering Laboratories, Inc. (SEL) in 2006. Presently, he is a senior protection engineer at SEL Engineering Services, Inc. (SEL ES). Kamal has experience in protection system design, system planning, substation design, operation, remedial action schemes, synchrophasors, testing, and maintenance. Kamal is a licensed professional engineer in the U.S. and Canada, senior member of the IEEE, member of many working groups in the IEEE Power System Relaying and Control Committee, and holds two patents.