Field Experience Commissioning Reactor Projects

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***Abstract*—This paper discusses the commissioning of various San Diego Gas & Electric (SDG&E) shunt reactor installation projects, along with the protection upgrades for tertiary, line, and bus-connected reactors within the SDG&E system. In 2019, SDG&E began upgrading reactor protection systems by incorporating modern relays and protection practices that were later published in IEEE C37.109-2023 [1]. That same year, SDG&E presented the paper "SDG&E Relay Standards – Updating Tertiary Bus and Reactor Protection" [2], which outlined the approach for upgrading protection on 500/230/12 kV transformer tertiary buses and reactors. Since then, SDG&E has successfully upgraded and commissioned shunt reactors, implementing the latest protection and turn-to-turn schemes as detailed in the most recent IEEE standards revision.**

SDG&E line reactors are located on series-compensated lines and various literature exists that discusses the challenges for sensitive protection elements [1]. The paper also highlights the latest protection techniques for turn-to-turn faults and how set points were optimized for each installation to achieve the greatest benefit from sensitive protection elements. Highlights of field commissioning are included, with references to actual field events.

I. Introduction

Shunt reactors are applied to control the system voltage and can be applied as bus, line, and tertiary bus reactors. The location and size of the reactors require studies and procedures as discussed in IEEE Std C37.109-2023, IEEE Guide for the Protection of Shunt Reactors [1] and IEEE Std C57.21-2021, IEEE Standard Requirements, Terminology, and Test Code for Shunt Reactors Rated Over 500 kVA [3]. Renewable energy and offshore projects use variable shunt reactors (VSRs) [4] [5] [6]. Fig. 1 shows the typical bus, line, and transformer tertiary reactors.

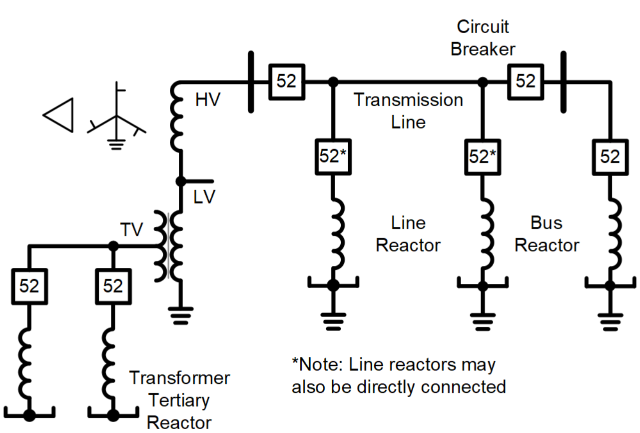

Fig. 1. Shunt Reactor Typical Applications (CIGRE 693) [6]

II. Types of Reactors and Applications

Reactors can either be a dry type (air-core or iron-core) or oil immersed. Modern dry-type air-core reactors are applied from transmission to distribution in electric power systems, including extra-high-voltage (EHV) shunt reactors. Oil-immersed reactors are typically popular for EHV shunt reactor applications. IEEE C37.109-2023 discusses the design differences between air- and iron-core designs, including the fact that the number of turns for the same inductor is much higher in air-core reactors as compared to iron-core reactors [1].

III. SDG&E Standards and Benefits for Reactor Protection Upgrades

In upgrading the protection for substation reactors, SDG&E was focused on obtaining the following benefits:

1. Incorporate the latest IEEE standards in reactor protection.
2. Incorporate the latest methodologies for reactor fault sensing.
3. Provide a redundant protection approach.
4. In particular, provide dependability and security in sensing developing turn-to-turn faults.
5. Use protective relays that can provide the required number of current and voltage inputs.
6. Incorporate protective relays that have programmable logic to enable the use of SDG&E protection and supervisory control and data acquisition (SCADA) standard protocols.
7. Provide efficient relay monitoring for system operating events.
8. Provide phasor measurement outputs and communication to provide synchronized measurement of currents, voltages, and protection elements.

SDG&E has two 500 kV line reactors, four substations with 12 kV tertiary reactors, and one substation with 69 kV bus reactors. Protection schemes for all applications have been updated with modern protection using the latest turn-to-turn methods and protection guidelines, as discussed in IEEE C37.109-2023. Fig. 2, Fig. 3, and Fig. 4 show the protection scheme details. The SDG&E line and bus reactor standards use circuit breakers for protection trips and reactor switchers for controlled closing and opening.

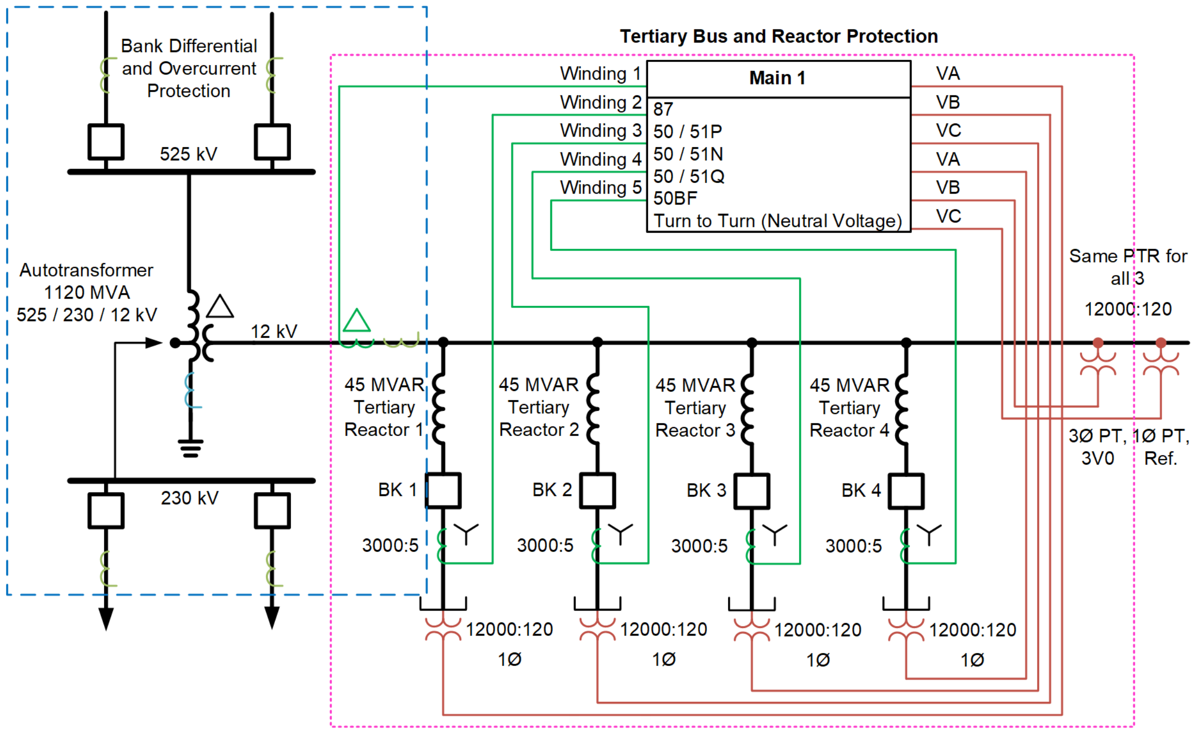

Fig. 2. Tertiary Reactor Scheme A Protection

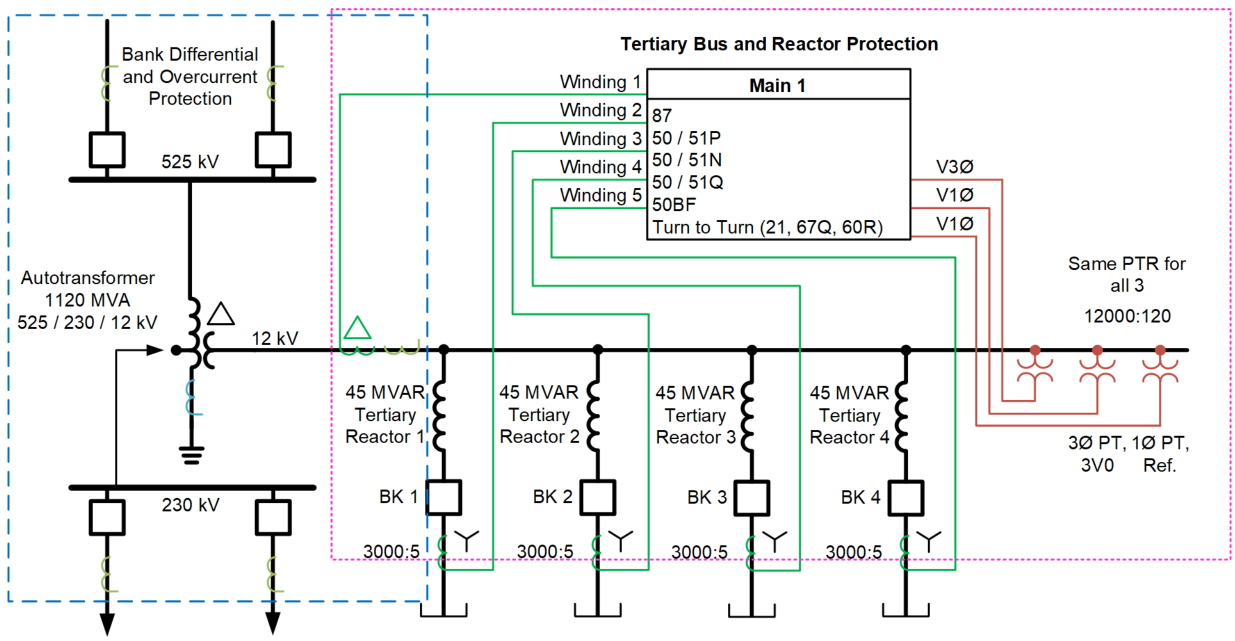

Fig. 3. Tertiary Reactor Scheme B Protection

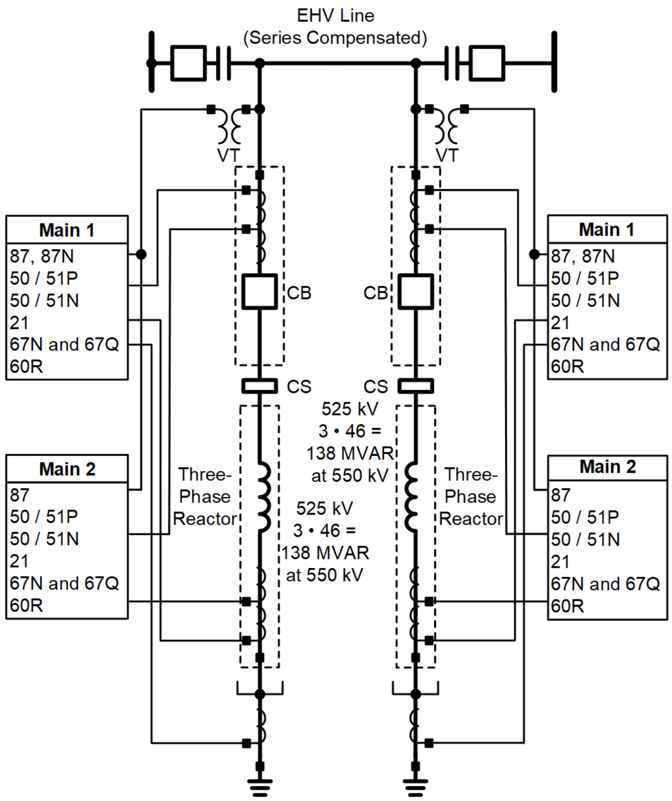

Fig. 4. Line Reactor Protection

A. Bus Reactor Protection

The details for bus reactor protection are shown in Fig. 5. The ultimate scheme will be to use two multifunction relays wired in the same way; however, because of project constraints, it was decided to add only the Main 1 relay with the functions as shown in the figure. The Main 2 relay details were not adjusted. The Main 1 relay includes multiple sensitive overcurrent levels that are set based upon system details, reactor switcher failure, and by using multiple turn-to-turn methods (distance, directional overcurrent, and 60R normalized voltage and current, which is also referred to as V2 I2).

B. Tertiary Reactor Protection

The SDG&E tertiary reactor application is 4 x 45 MVAR (for additional details, refer to Section IV.B). The SDG&E tertiary reactor protection is provided by two relays, both have low-impedance differential (87), overcurrent (OC [50/51]), and multiple turn-to-turn methods (distance, directional OC, and V2 I2) [1] [7] [8] [9]. For most tertiary reactors, Scheme A works as both the voltage differential and negative-sequence OC for turn-to-turn, and Scheme B has multiple turn-to-turn methods (distance, negative-sequence OC, and V2 I2). Scheme A and Scheme B are shown in Fig. 2 and Fig. 3, respectively.

C. Line Reactor Protection

SDG&E uses two relays, both set up as low-impedance differential, OC, and multiple turn-to-turn methods (directional OC [10], V2 I2 ratio [4], and impedance measuring [5]). Section IV discusses the details of the protection schemes, as well as the field results and analysis. For more details, refer to Section IV.B. The line reactor protection diagram is shown in Fig. 4. Reactor switchers also help in reducing the inrush current.

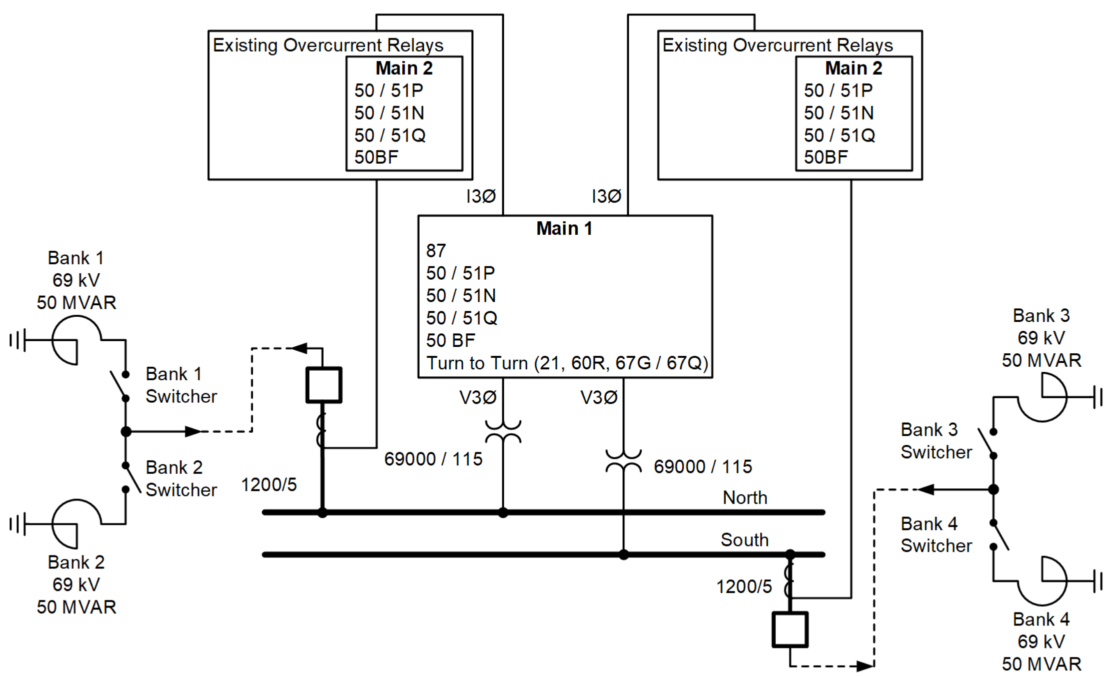

Fig. 5. Bus Reactor Protection

IV. Field Commissioning of SDG&E Reactor Projects

This section will discuss the various reactor design additions, commissioning data, results, and lessons learned.

A. 69 kV Bus Reactor Banks

1) Original Field Installation

The field installation included four 50 MVAR 69 kV air-core reactor banks connected in a grounded-wye configuration. These reactors were originally installed to regulate the 230 kV bus voltage to compensate for the high charging current from three 230 kV lines with underground cables connected at the substation. Each reactor bank had a reactor switcher and two reactor switchers were sourced by two 69 kV circuit breakers. The original protection consisted of two microprocessor overcurrent relays, providing fault overcurrent protection. Sensitive turn-to-turn protection was not applied. The only current transformers (CTs) available were the circuit breaker CTs that sourced the overcurrent relays.

The protection strategy was to clear reactor faults with the circuit breakers and the reactor switchers were to be used for switching only. In the past, there had been a fault on one of the single-phase reactors, which appeared to start as a low-level fault that did not reach an overcurrent setting. It evolved into a high-current line-to-ground fault that was ultimately cleared by opening the source circuit breaker. Refer to Fig. 6 for the example of the SDG&E bus reactor project field installation.

Fig. 6. SDG&E Bus Reactor Project Field Installation Example

2) New Project

As discussed in Section III, a project was started to upgrade the existing protection. The design team understood that with the lack of reactor CTs, there was no option to provide differential protection. Given that the reactors were air-core units, this was not a significant drawback because the most common faults on 69 kV air-core reactors are turn-to-turn faults, which are not detected by differential protection. The design team selected a multifunction programmable microprocessor relay to provide: 1) redundant turn-to-turn protection using modern techniques and 2) the ability to sensitize overcurrent protection when only one reactor was being sourced by the connected circuit breaker. The bus reactor installation is shown in Fig. 6.

The turn-to-turn protection would consist of: 1) V2 I2, 2) directional negative-sequence and zero-sequence overcurrent, and 3) impedance measurement. It was decided that the turn-to-turn protection would be used to trip the connected reactor switcher if a single reactor was in service or if two reactors were in service, sequential tripping would be employed. In this situation, the lower numbered reactor (Reactor 1 of Reactors 1–2 or Reactor 3 of Reactors 3–4) would be tripped. On time delay, if the turn-to-turn fault was still present, the remaining reactor would be tripped.

The overcurrent fault settings were provided to enable decreased pickup levels when a single reactor bank is in service. This was done by making the two-bank phase and ground settings always in service and by enabling the lower current single-bank settings by using torque control from a latch that is set when only one bank is in service.

Because the reactor switchers are used for turn-to-turn clearing, it was decided to provide breaker failure protection for the failure of a reactor switcher to operate. Breaker failure protection was provided to trip the source circuit breaker if a connected switcher failed to operate.

Originally, the design values were to be used for the impedance set points and a value of 97 percent was the trip value. After review, the design team decided to use the field impedance measurement of each reactor phase to allow the set points to be calculated. Even though the measured values are quite close to the design values, it made sense to use the measured values for the highest accuracy.

3) Commissioning Tests (2022)

Factory acceptance testing was performed to confirm the operation of all protective schemes. This testing was shared with the SDG&E protection team via an online meeting. In addition, the SDG&E team met with the protection field group to present the new additions.

A detailed commissioning test was prepared by the project design team for use during field commissioning. This test served as a script for use by the Control Center during the energizing and testing of each reactor, ensuring that the transmission switching operators were fully aware of the required switching sequence.

The commissioning went very well, with all recorded values in the expected ranges. Since the protection system commissioning in September 2022, there has been only one protective operation.

Fig. 7 shows the lab test to verify the logic for all turn-to-turn detection methods and other faults (done using the field events). All three turn-to-turn methods were able to detect the event shown in the figure. Lab testing was also performed to verify the correct phase identification and front-panel light-emitting diodes (LEDs), as well as other ways to verify the operation (see Fig. 8). The Fig. 7 event shows an A-phase turn-to-turn evolving fault and turn-to-turn detection using three methods (impedance, V2 I2, and directional OC). All three sensitive turn-to-turn methods were able to detect these faults quickly before the fault evolved into a larger fault.

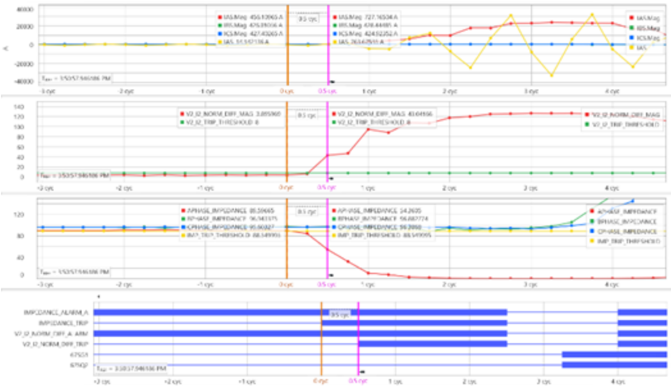

Fig. 7. Bus Reactor Lab Testing – Turn-to-Turn Methods

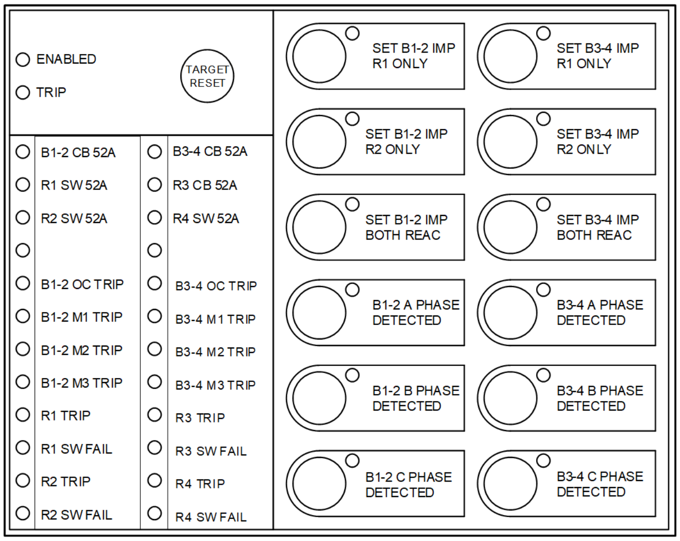

Fig. 8. Bus Reactor Front Panel

4) B1 First Tertiary Reactor Project

The first tertiary reactor project was completed at a 500/230/138/69/12 kV substation. The original autotransformer bank was installed in 1984. The installation included a 500/230/12 kV autotransformer bank with four 45 MVAR air-core tertiary reactors that were connected on a 12 kV delta tertiary bus with 12 kV ground detector transformers. The tertiary reactors were installed to compensate for the high charging current of the single connected 500 kV transmission line at the substation and the autotransformer bank was directly connected to the line at this terminal. Each reactor bank had a 12 kV vacuum circuit breaker connected to the tertiary bus with the breakers connected on the neutral side of the reactor banks. The 1984 protection consisted of redundant electromechanical transformer differential relays, which were connected to include the tertiary bus and reactors in the differential zone. On the 500 kV side, there were electromechanical overcurrent relays and these electromechanical overcurrent relays were connected on the 12 kV tertiary. Electronic relays that provided neutral overvoltage protection were also installed.

In 2004, the autotransformer bank protection was modified when a 500 kV gas-insulated switchgear (GIS) was installed. The new protection consisted of new redundant microprocessor differential relays with the differential zone bounded by the transformer tertiary bushings. A microprocessor tertiary bus differential relay was installed, in addition to two 12 kV tertiary overcurrent relays. Four microprocessor relays were installed to provide neutral overvoltage protection.

a) B1.1 New Project: Modern Microprocessor Multifunction Programmable Relays

As discussed in Section I, the SDG&E protection team wanted to realize the benefits of upgrading the tertiary bus and reactor protection by providing improved turn-to-turn fault detections performance. As discussed in the 2019 paper [2], which was previously mentioned, the new project would consist of two redundant microprocessor multifunction relays and one microprocessor overcurrent relay. Protection functions were as follows:

1. Tertiary bus differential, tertiary multiphase overcurrent, and bus negative-sequence overcurrent, all tripping the autotransformer bank.
2. Reactor turn-to-turn protection, including zero-sequence voltage differential 87V and negative-sequence overcurrent, which would trip individual reactor circuit breakers (CBs).
3. Vacuum bottle failure, which would trip the autotransformer bank.
4. Breaker failure, which would trip the autotransformer bank for circuit breaker failure in the 12 kV reactor.
5. Tertiary ground fault alarm.
6. Relay pushbuttons that were used to set the null voltages during commissioning of the reactor protection. To ensure security of setting the pushbuttons, 5-second timers were programmed to prevent a momentary pushbutton operation from modifying the null set points.
7. High-resolution event activity, including oscillographic events and phasor measurement units (PMUs), would also be provided.

The connection details are shown in Fig. 2, with redundant connections of Scheme A used.

b) B1.2 Commissioning Tests (2023)

As was done for the bus reactor project, factory acceptance testing was performed to confirm the operation of all protective elements.

A detailed commissioning test was prepared by the project design team for use during field commissioning. The commissioning test included the use of temporary event report settings to enable triggering an event for each reactor switch close operation. This enabled review of the Common Format for Transient Data Exchange (COMTRADE) files taken during energizing to analyze the transient waveforms on energizing. Commissioning tests included:

- Energizing of reactor banks in turn.
- In-service testing of the tertiary bus differential.
- Check and log voltages and currents.
- Check and log neutral voltages and null set points.
- Check and log negative-sequence currents.

During the in-service testing of the tertiary differential function, SDG&E found that the polarity on both transformer tertiary currents was incorrect, yielding high differential operating currents. To correct this, the polarities were rolled at the relays, which resulted in zero-differential operating currents. One other item was found: the null voltage set points were unintentionally removed during the setting change process to remove the temporary event report settings. These null value set points are monitored by green lights at the pushbuttons. To reset the null values, the reactor circuit breakers were operated a second time, which restored all null set points. In total, the commissioning was successful with all recorded values in the expected ranges. There has been one protective operation since the protection system commissioning in November 2023.

The Reactor 4 energizing event report is presented in Fig. 9.

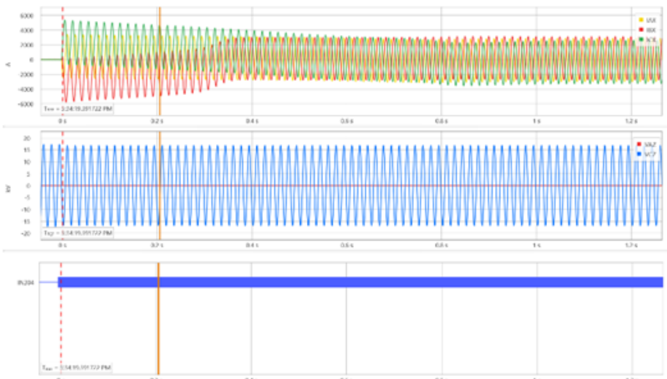

Fig. 9. Tertiary Reactor 4 Energizing Event

5) B2 Second Tertiary Reactor Project

The second tertiary reactor project was completed at a 500/230/12 kV substation. The installation included two 500/230/12 kV autotransformer banks, each with four 45 MVAR air-core tertiary reactors that were connected on separate 12 kV delta-tertiary buses, with 12 kV ground detector transformers. The tertiary reactors were installed to compensate for the high charging current of the source 500 kV transmission line and the two 230 kV line underground cables connected at the substation. Each reactor bank had a 12 kV vacuum circuit breaker connected to the tertiary bus, with the breakers connected on the neutral side of the reactor banks. For each autotransformer bank, the protection consisted of redundant microprocessor differential relays, with the differential zone bounded by the transformer tertiary bushings. A microprocessor-based tertiary bus differential relay was installed, in addition to two 12 kV tertiary overcurrent relays. Four microprocessor-based relays were installed to provide neutral overvoltage protection.

The tertiary reactor installation for the second project is shown in Fig. 10. As shown, the reactor circuit breaker is connected on the neutral side of the reactor and the neutral voltage transformer is connected to the tied breaker terminals for the neutral.

Fig. 10. Tertiary Reactor Installation Example

a) B2.1 New Project: Modern Microprocessor Multifunction Programmable Relays

Similar to the first tertiary project site, the SDG&E protection team wanted to realize the benefits of upgrading the tertiary bus and reactor protection, providing improved turn-to-turn performance. As done on the first project, the new project would consist of two redundant microprocessor multifunction relays and one microprocessor overcurrent relay. Protection functions for each autotransformer bank were provided as described for the first project, but also included Scheme B 1) V2 I2, 2) negative-sequence overcurrent, and 3) impedance measurement, all tripping individual reactor circuit breakers.

Auxiliary potential transformers (PTs) connected to the phase-to-ground connected ground detector transformer secondaries were installed to provide three-phase potential for the V2 I2 and impedance calculations for Scheme B.

The connection details are shown in Fig. 2 and Fig. 3 for Scheme A and Scheme B.

b) B2.2 Commissioning Tests (2023)

As done for the first tertiary reactor project, factory acceptance testing was performed to confirm the operation of all protective schemes.

Commissioning tests included:

- All tests previously noted for Project 1.
- For System B, check and log V2 I2 magnitudes.
- For System B, check and log phase impedances and impedance set points.

As shown in Fig. 11, the front panel for Scheme B on the second tertiary project provides indications and pushbuttons in a similar way to the bus reactor front panel that is shown in Fig. 8.

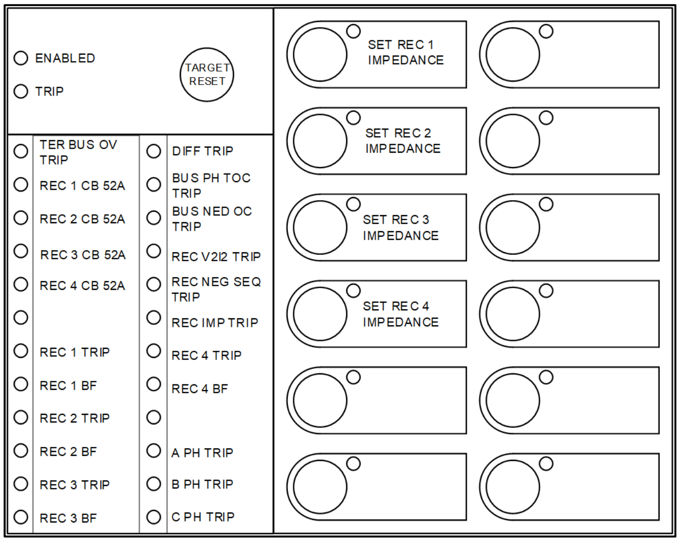

Fig. 11. Tertiary Reactor Front Panel (Scheme B)

Event 1: Reactor 1 Trip on Negative Sequence

1. On energizing, Reactor 1 tripped on the System A negative-sequence overcurrent (see Fig. 12). The three-phase currents were well balanced, and a negative-sequence output was not expected. The System B relay, operating with the same negative-sequence settings, did not pick up, showing a much lower negative-sequence calculation. This same operation occurred when energizing the other reactors.
2. During commissioning, the negative-sequence overcurrent functions for all reactors were removed by setting the overcurrent torque control inputs to "0." This was done on both System A and System B relays.

Additional details are provided in Section V. Fig. 12 shows the event report for the Reactor 1 trip, which illustrates the time-out of the negative-sequence overcurrent function.

Fig. 12. Negative-Sequence Overcurrent Trip Reactor 1 (Event 1)

Event 2: Reactor 4 Trip on 60R V2 I2

1. Reactor 4 tripped on normalized negative-sequence 60R on the System B relay. The trip occurred at a calculated value of 3.16 percent, which is above the set point of 3.0 percent (see Fig. 13).
2. During commissioning, the normalized negative-sequence 60R protection was removed from service in the System B protection logic settings and later returned to service after a setting change.

Additional detail is provided in Section V. Fig. 13 shows the event report for the Reactor 4 60R relay operation.

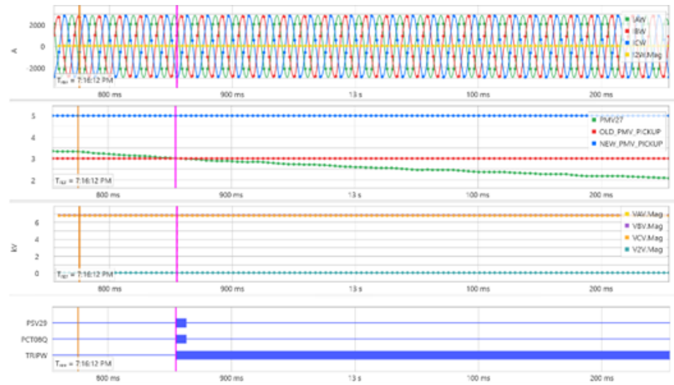

Fig. 13. Reactor 4 60R Trip Output (Event 2)

Event 3: Reactor Trips During Tertiary Ground Event

1. Reactors 1, 2, and 4 tripped on differential zero-sequence voltage (87V). The trips occurred during a tertiary bus ground (Reactor 3 not in service). Refer to Fig. 14.
2. After the tertiary bus ground was no longer present, the reactors were returned to service with no protective operations.
3. The protection logic settings were revised.

Additional detail is provided in Section V. The relay event showing the three reactor trips is shown in Fig. 14.

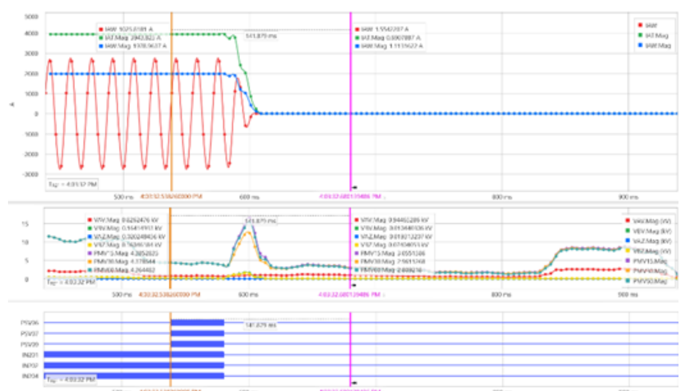

Fig. 14. Zero-Sequence Voltage Differential 87V Trips (Event 3)

Event 4: Tertiary Reactor (No Event Record)

Eight months after commissioning, Reactor 5 tripped when an 87V differential zero-sequence voltage trip was issued. The reactor was switched out of service for follow up. The circumstances were as follows:

1. Following the trip a relay crew went to retrieve the relay event record and discovered that there was not an event record for the event; a number of other event records were present, so it appeared that the event buffer was full.
2. A subsequent field inspection with the reactor switched out could not locate a reason for the trip.

Additional detail is provided in Section V.

Event 5: Reactor 5 Trip Zero-Sequence Voltage Differential 87V

The circumstances were as follows:

1. Ten months after its commissioning, Reactor 5 tripped when a zero-sequence voltage differential trip was issued. Refer to Fig. 15.
2. The relay event record showed that there was a Reactor 5 neutral overvoltage present at the relay prior to the closing of the Reactor 5 circuit breaker. The PMU data were now available, allowing a review of the Reactor 5 neutral voltage.

Additional detail is provided in Section V. The November 2024 Reactor 5 trip event is shown in Fig. 15.

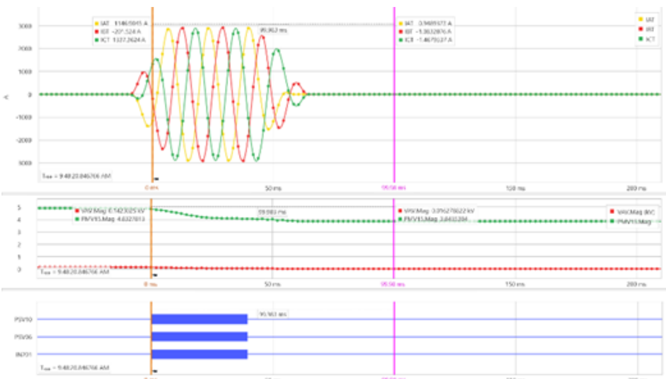

Fig. 15. Reactor 5 Neutral Overvoltage Trip (Event 5)

6) B3 Third Tertiary Reactor Project

The third tertiary reactor project will be completed on one of three autotransformer banks at a 500/230/12 kV substation. The autotransformer bank with the tertiary reactors was installed in 2018. The installation includes one 500/230/12 kV autotransformer bank with four 45 MVAR air-core tertiary reactors that are connected on a 12 kV delta-tertiary bus with 12 kV ground detector transformers. The tertiary reactors were installed to compensate for the high charging current of the three 500 kV transmission lines that are connected at the substation. Each reactor bank has a 12 kV vacuum circuit breaker connected to the tertiary bus with the breakers connected on the neutral side of the reactor banks. The original protection consisted of redundant microprocessor differential relays with the differential zone bounded by the transformer tertiary bushings. A microprocessor tertiary bus differential relay was installed, in addition to two 12 kV tertiary overcurrent relays. Four microprocessor relays were installed to provide neutral overvoltage protection.

a) B3.1 New Project – Modern Microprocessor Multifunction Programmable Relays

Similar to the second project, this new project consists of two redundant microprocessor multifunction relays and one microprocessor overcurrent relay. Protection functions for each autotransformer bank are identical to the second project, using Scheme A and Scheme B as previously discussed.

b) B3.2 Commissioning Tests (2025)

As done for the previous tertiary reactor projects, factory acceptance testing (including the Real Time Digital Simulator [RTDS]) will be performed to confirm the operation of all protective elements.

Commissioning tests will be completed and will follow the same procedure used for the second project.

B. 500 kV Line Reactor

1) Original Field Installation

The field installation included a replacement 138 MVAR, 500 kV oil-filled reactor bank connected in a grounded-wye configuration. The reactor bank was connected on a 500 kV line terminal, with the original reactor bank installed as a part of a major project in 1984. The reactor was installed to regulate the 500 kV system voltage to compensate for the high charging current of the connected line and one other 500 kV line at the substation. The original reactor was switched by a 500 kV circuit breaker. On the new project, a 500 kV reactor switcher was added for breaker control; whereas, the circuit breaker was provided for fault switching only. It is interesting that a circuit switcher was originally installed in 1984; however, equipment difficulties resulted in the removal of the device during the 1990s. The existing protection consisted of two microprocessor differential relays and one microprocessor overcurrent relay.

In Fig. 16, a single phase of the line reactor installation is shown.

Fig. 16. Line Reactor Installation Example

2) New Project

In addition to the new reactor switcher, the SDG&E protection team decided to upgrade the reactor protection. The design team selected to replace the existing differential relays with two modern microprocessor differential relays that would be capable of including sensitive turn-to-turn protection techniques. The existing overcurrent relay was maintained; this relay was being used to enable the reactor mechanical device trips, in addition to overcurrent protection. The turn-to-turn protection would consist of: 1) V2 I2, 2) directional zero-sequence overcurrent, and 3) impedance measurement.

3) Commissioning

Factory acceptance testing, including the RTDS, was performed to confirm the operation of all protective elements.

The commissioning test included the use of temporary event report settings to enable the triggering of an event for the reactor switcher close operation. This enabled the review of

COMTRADE files taken during energizing to analyze the transient waveforms on energizing. Commissioning tests included:

- In-service testing of the tertiary differential.
- Check and log voltages and currents.
- Check and log zero-sequence currents.
- Check and log 60R V2 I2 magnitudes.
- Check and log phase impedances and impedance set points.

Fig. 17 shows the front panel for the line reactor.

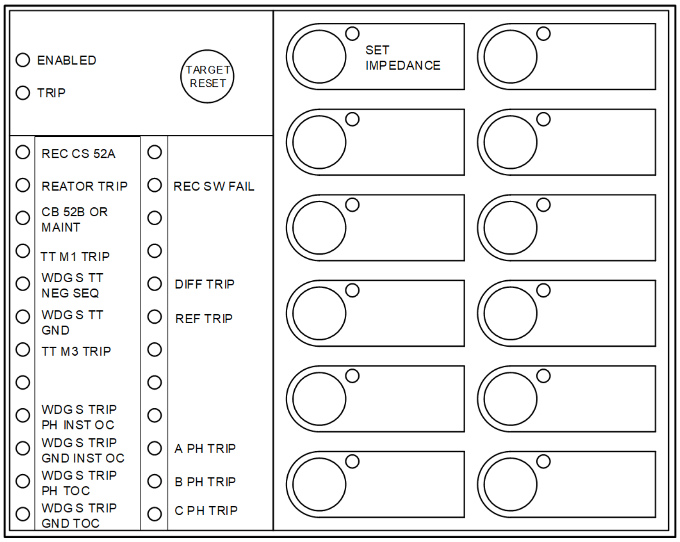

Fig. 17. Line Reactor Front Panel

Event 1: 60R (V2 I2) Reactor Trip During Preliminary Testing

During preliminary testing, a 60R V2 I2 output was issued with voltage input and no load. The steps taken were as follows:

- Added logic to prevent output with the new maintenance test switch on. For more details, see Section V.
- On energizing and on delay, an output from a temperature device tripped the reactor through the multifunction overcurrent relay. Technicians checked and revised the temperature device settings.

Event 2: Line Reactor Trip During Energization

On re-energizing the 500 kV reactor bank, a trip occurred on 60R V2 I2. This event is shown in Fig. 18.

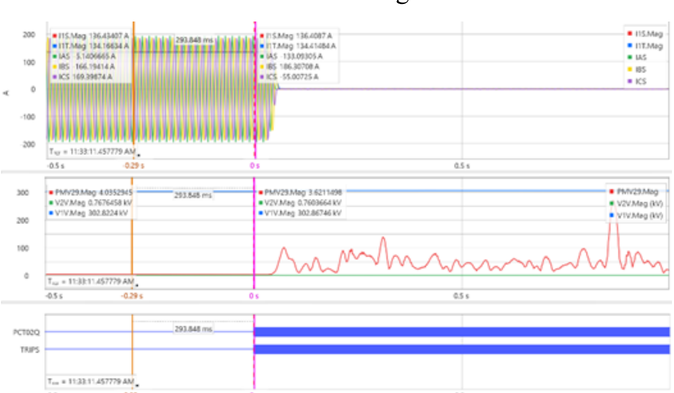

Fig. 18. 60R V2 I2 Trip on Energizing 500 kV Reactor

Refer to Section V for details. After revising the 60R V2 I2 settings due to the energization trip, the 500 kV line reactor was successfully energized, as shown in Fig. 19.

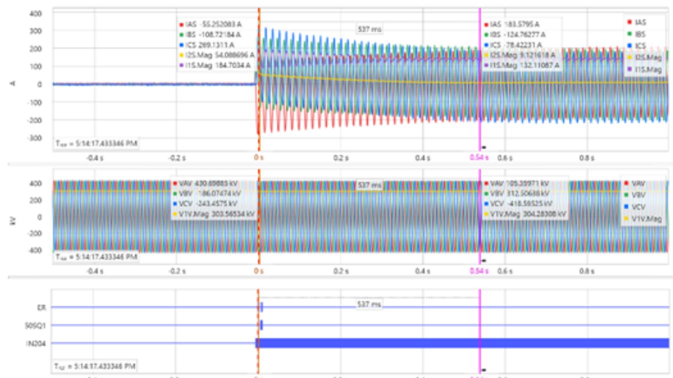

Fig. 19. Energizing of 500 kV Reactor – No Trip (Event 2)

Fig. 19 and Fig. 20 show the energization record of the line reactor with no trips. There has been one protective relay operation since the reactor protection system commissioning in July 2024.

=>met dif a

87B-9029 SEL-487E Date: 06/15/2024 Time: 17:25:36:847

LINE REACTOR SYS B

Operate Currents (per unit)			Restraint Currents (per unit)		
IOPA	IOPB	IOPC	IRTA	IRTB	IRTC
0.00	0.00	0.00	1.81	1.80	1.80

2nd Harmonic Currents (percentage of IOPA, IOPB, IOPC)

IOPAF2	IOPBF2	IOPCF2
0.00	0.00	0.00

4th Harmonic Currents (percentage of IOPA, IOPB, IOPC)

IOPAF4	IOPBF4	IOPCF4
0.00	0.00	0.00

5th Harmonic Currents (percentage of IOPA, IOPB, IOPC)

IOPAF5	IOPBF5	IOPCF5
0.00	0.00	0.00

Enabled Windings: S, T

Tap and Matrix Compensation: Reference Terminal = S

	Terminal Currents				Tap Comp.	Matrix Comp.	
Phase A	(A. primary)	(A. secondary)	(DEG)		(per unit)	(per unit)	(DEG)
IAS	136.94	0.62	0.00		0.90	0.90	0.00
IAT	137.08	2.28	–179.72		0.90	0.90	–179.72
Phase B							
IBS	136.44	0.62	–120.11		0.90	0.90	–120.11
IBT	136.63	2.28	60.08		0.90	0.90	60.08
Phase C							
ICS	136.36	0.62	120.64		0.90	0.90	120.64
ICT	136.61	2.28	–59.43		0.90	0.90	–59.43

Fig. 20. Line Reactor Energization – Meter Data

V. Lessons Learned and Observations

Tertiary Event 1 – Negative-Sequence Overcurrent

A review of the negative-sequence overcurrent trip events showed that the System A relay calculated a higher negative-sequence value than the System B relay. The voltage reference settings for the two relays were reviewed. There are two sets of three voltage inputs labeled V and Z. Table I shows the voltage assignments.

TABLE I
PROTECTION SYSTEMS A AND B VOLTAGES

	System A	System B
VA	Reactor 1 Neutral	Tertiary Bus A-Neutral
VB	Reactor 2 Neutral	Tertiary Bus B-Neutral
VC	Reactor 3 Neutral	Tertiary Bus C-Neutral
ZA	Reactor 4 Neutral	Not Used
ZB	Ground Detector	Ground Detector
ZC	B–C Reference	B–C Reference

The System A and System B relays were both set with a voltage reference of Voltage V. In System A, only the ZC voltage normally has a set voltage input, whereas the other assigned voltages are at or near zero under normal system conditions. Using RTDS testing, a voltage reference change to Voltage Z was made for the System A relay, allowing the use of the ZC voltage as a reference. Testing showed a predictable negative-sequence overcurrent calculation, well under the set point. A test was run using the reactor current values from the relay trip event records and there was no high negative-sequence calculation and no trip output. The System B voltage reference setting was left on the V voltage because the three-phase voltages are set values under normal conditions.

With this revision, the negative-sequence overcurrent settings were set at the original sensitive settings for both Systems A and B. Both systems had the torque controls placed on a "1" setting to return the function to service.

After this review, the frequency reference settings were also tested. The original settings were V voltage for both Systems A and B. For the same reasons as previously discussed, it was determined to set the System A local frequency reference Source 1 as voltage ZC with no alternates. For System B, with more flexibility, the local frequency sources were set as VA, VB, and VC, with the alternate set as ZC. This allows for redundancy between the two systems.

Tertiary Event 2 – Reactor 4 60R V2 I2

A review of the Reactor 4 60R V2 I2 trip event showed that the System B relay calculated a difference of 3.16 percent, which is greater than the 3 percent set point. This is the first application of V2 I2 on the SDG&E system, and the 3 percent set point was chosen by the protection design team based upon industry practice. The negative-sequence values were in order; note that the voltage reference issue did not apply for the System B relay. Based upon this review, it was determined to raise the V2 I2 set points to 5 percent to provide security. The setting change was made and the 60R V2 I2 protection was then returned to service. It was understood that ultimately the in-service V2 I2 values could be observed using PMU data to allow review of the calculated values for all reactors.

Tertiary Event 3 – Zero-Sequence Voltage Differential

A review of the zero-sequence voltage differential trip event showed that the System A relay issued simultaneous trips for Reactors 1, 2, and 4. A tertiary ground detector voltage input showed that a tertiary bus partial ground was detected by the open-delta ground detector system. This tertiary ground should not result in reactor tripping because the neutral overvoltage protection uses an algorithm to calculate the system operating voltage. The operating system voltage is calculated by subtracting the reactor neutral-ground voltage, Vng, from the ground detector voltage V0. The wiring in the field resulted in opposite polarities of these two voltage phasors, yielding a high-voltage output, rather than a low-voltage output due to additive voltages. The trip set point is 4.0 volts and all three reactors had operating voltages greater than 12 volts. This resulted in the tripping of all three reactors. It was determined that the protection logic would be revised to add the two voltages rather than subtracting, resulting in no trip outputs for the tertiary bus ground. The ground detector and neutral voltages are normally at or near zero; therefore, the phasing of these voltages cannot be confirmed during commissioning.

Tertiary Event 4

A review of the differential zero-sequence voltage trip event showed that the System A relay issued a trip for Reactor 5. There was no event report issued. It appeared that the event buffer was full because of excessive event records. On review of the Sequential Events Recorder (SER) data, it was discovered that multiple events were being triggered during routine events, such as reactor circuit breaker operation. This came about because operation of the breakers, both trip and close, resulted in negative-sequence currents and reactor neutral voltages due to the sequential operation of the 12 kV tertiary breaker poles. These operations were not anticipated when the settings were created, when there was a focus on observing low-level inputs that could occur on turn-to-turn fault initiation.

It was decided to remove the low-level current and voltage inputs from the event report settings. This was done to ensure the ability to record system data during trip events. In addition, the development of PMU points became a priority because this would allow the team to observe relay measurements and calculations during system events.

Tertiary Event 5

A review of the differential zero-sequence voltage trip event showed that the System A relay issued a trip for Reactor 5. The event record was retrieved and a review showed that a Reactor 5 neutral voltage was present prior to closing the Reactor 5 circuit breaker. The reactor neutral voltage was high enough to cause the 87V set point to be exceeded and the 60-cycle timer for the function had been exceeded. When the circuit breaker was closed, with the time-out already occurring, the 87V protection issued a trip output with no additional delay. This can be observed in Fig. 15.

The System A reactor neutral voltage PMU data had been connected for all station reactors starting in September 2024.

Ultimately, the PMU data were collected and reviewed. It was found that the Reactor 5 neutral voltage is often elevated when the reactor circuit breaker is open. As previously noted, the Reactor 5 neutral voltage was high enough to cause the 87V set point to be exceeded prior to closing the circuit breaker, which is a frequent occurrence for Reactor 5. After reviewing the PMU data, it was found that when the Reactor 5 circuit breaker is open, the Reactor 5 neutral voltage can be elevated when either the Reactor 6 circuit breaker or Reactor 8 circuit breaker is closed. The neutral voltage is highest when the Reactor 6 circuit breaker is closed; however, it also elevates when Reactor 8 is closed, and that was the case during the Reactor 5 trip.

In response to this study, two setting changes were made: 1) the 87V trip set point was raised for Reactor 5 and 2) the trip logic was changed to initiate the 60-cycle timer on the AND output of operating voltage above the set point and closed Reactor 5 circuit breaker. After making these changes, the PMU data will be reviewed to confirm the operation of Reactor 5. Data for all other station reactors were reviewed and only Reactor 5 neutral is affected by other reactor operations. The settings will be updated in April 2025 and additional testing will be conducted.

Line Reactor Event 1

During testing, with the line voltages connected to the relay prior to energizing the reactor, the relay technician found that a trip was issued to the trip output lockout relay (LOR) when the reactor switcher was closed. This trip was initiated by the normalized negative-sequence 60R protection. With no line voltage and no load current inputs, a V2 I2 differential detected input was asserted, as shown in Fig. 21.

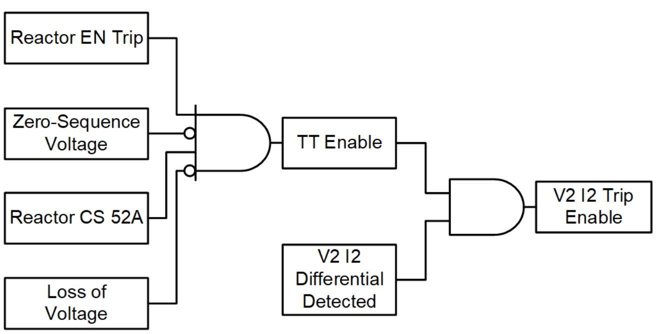

Fig. 21. Line Reactor 60R Protection Logic

When the reactor switcher 52A was asserted, the turn-to-turn enable was asserted. This resulted in a V2 I2 trip enabled output, causing an LOR trip output. It was decided to add an input to the AND gate, as shown in Fig. 22. This input would be asserted for either of the following: reactor circuit breaker open or maintenance switch that would be closed during de-energized testing. This switch was added, and operation of the switch or open reactor circuit breaker prevented the V2 I2 trip from asserting by adding logic to deassert the turn-to-turn enable when the new input was asserted. A relay LED was programmed to monitor the maintenance switch input to ensure that the maintenance switch would not be left asserted when testing was completed. This addition is shown in Fig. 22.

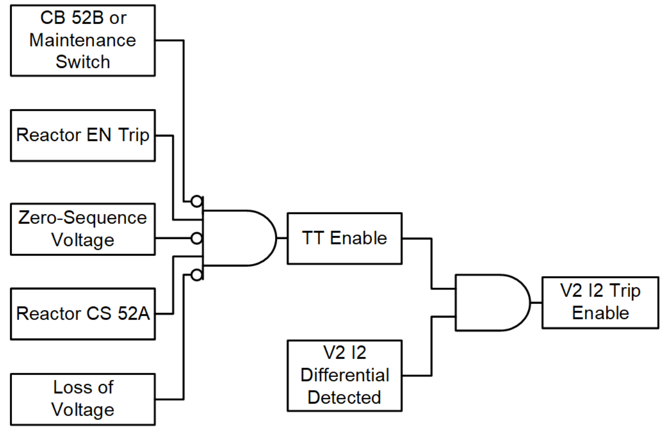

Fig. 22. Line Reactor 60R Protection Logic With Addition

Line Reactor Event 2

When the line reactor was energized, the 60R V2 I2 protection operated, tripping the reactor. A review of the event record showed that negative-sequence current was present, and it was determined that this was due to CT saturation. As shown in Fig. 19, when the reactor was successfully energized, there was a considerable dc transient on energizing. It has been noted that this can result in CT saturation, which is one of the reasons for disabling the differential protection for a time delay on first energizing. There was a 60-cycle delay timer for enabling the 60R protection; however, the 60R output was still asserted at the 60-cycle time-out. The trip set point was 3 percent and the calculated V2 I2 difference was 3.2 percent when the trip was issued. The decision was made to increase the set point to 5 percent, with the understanding that PMUs were being connected to allow monitoring of the 60R V2 I2 differential quantity. SDG&E felt that fine tuning the 60R V2 I2 set point can be made after the PMU data are available to review for a longer time period. The differential quantity will be reviewed during energizing and abnormal system conditions.

General Discussion – PMU Data Review

In general, the addition of PMU monitoring will add great value in allowing the observation of the functional elements within the reactor protection relays. With a better understanding of the key relay elements, it will be possible to fine tune the settings, allowing adaptive settings when warranted.

VI. Conclusion

This paper discusses the following points:

- Protection standard design using IEEE C37.109-2023 for line and/or bus and tertiary reactor protection [1].
- Lab test and logic validation helped in reducing the commissioning time and efforts.
- Use of a commissioning test aids the process for testing new equipment and verifying new settings. The test serves as a script to define the required field testing and provides the Operations team with the needed switching procedure.
- Field analysis and lessons learned for various reactor protection for sensitive turn-to-turn protection.

- Continuous monitoring of sensitive turn-to-turn protection is being performed by SDG&E.

VII. Acknowledgment

The authors gratefully acknowledge the contributions of Arthur Giourdjian from SDG&E and Chris Knox and Skyler Corrigan from SEL for their support for various projects and event analysis.

VIII. References

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IX. Biographies

Kawika Lawlor was born and raised in San Diego. He graduated from Arizona State University with his B.S. in Electrical Engineering in 2013 and his M.S. in Power Systems Engineering in 2014. While in school, Kawika got his first exposure to the power industry as a substation design engineer intern. After graduating from college, he started working at Arizona Public Service (APS) as a rotational engineer. He gained experience in grid operations, generator protection/testing, substation design and apparatus engineering, after which he was permanently placed into grid operations. After years in grid operations at APS, Kawika made the move back to San Diego and joined SDG&E's Grid Operation Engineering group as a Senior Engineer. In 2020, Kawika transitioned into the Supervisor of Outage Coordination, then in 2021 moved to be the Grid Operations Engineering Manager. In 2022, Kawika transitioned to the Grid Control Manager where he was responsible for the transmission operators and the support teams. After 15 months, Kawika moved into his current position as the System Protection Manager. In 2021, Kawika completed his education goals by obtaining his MBA.

Sergio Flores Castro received his B.S. degree in Electrical Engineering from the University of Nevada, Las Vegas in 2012. He earned a certificate in Power Systems from the University of California, San Diego in 2016. In 2013, he joined San Diego Gas & Electric (SDG&E) as an associate engineer, rotating through Smart Grid, District Engineering, and System Protection Engineering. He spent 8 years in System Protection Engineering, working on both distribution and transmission systems as an engineer and team lead. Since 2022, he has been in the System Protection Maintenance group, where he supervises relay technicians. Sergio is a Registered Professional Engineer in the State of California.

Bill Cook is retired from engineering positions at San Diego Gas & Electric (SDG&E) Company. Bill started his career at SDG&E in 1976 as an engineer in the SDG&E Control Center. He moved to the field in 1982, working 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 Life 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. Bill is currently working as a consultant with Schweitzer Engineering Laboratories, Inc. (SEL) since his retirement from SDG&E.

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 principal 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 IEEE, chair/member of many working groups in the IEEE Power System Relaying and Control (PSRC) Committee, and vice chair of PSRC K-Substation Protection Subcommittee. Kamal is the project manager for IEEE Power & Energy Society (PES) Workforce Initiative (2023–2025) and holds four patents.

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