

A Collection of Bedtime Stories for Protection Engineers - Volume 1

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Abstract— This technical paper is a collection of recent events on Con Edison’s power system. Each event will have its own section for background, root cause analysis, fault calculation study and corrective action plan. These events demonstrate the uniqueness of the Con Edison power system, challenges, and lesson learns. Highlights of each are below:

Event #1 occurred during an external phase to ground fault. A line current differential scheme mis-operated due to false differential current being introduced at one terminal’s CTs on account of inter-core coupling on a GIS installation. Temporary and permanent corrective action plans will be discussed.

Event #2 also occurred during an external phase to ground fault. Multiple transmission lines in the vicinity over-tripped due to mis-operation of legacy pilot wire relaying. The focus will be on event analysis of all these over-trips and the corrective action plan.

Event #3 occurred during the commissioning process of a group of new power system elements. An undetected single-phase condition occurred when one pole of a circuit breaker remained stuck closed after the breaker had been switched open. This began a chain of events due to the unusual power system condition. Several faults developed, and protection systems operated to clear them.

Event #4 occurred during a mechanical failure of power distribution transformer’s load tap changer (LTC). It led one particular type of directional phase time overcurrent relay element to mis-operate on circulating current. The discussion will focus on calculation and comparison of different operating principles of different directional elements, revealing a limitation of quadrature polarizing. The corrective action plan will also be described.

Event #5 occurred during an external phase to phase fault. One terminal that was 3 buses away from the fault over-tripped on a line current differential scheme that had been in service for more than 5 years. One of the circuit breakers on that line, however, had recently been replaced and a CT polarity error was introduced in the wiring during that breaker replacement. The discussion will cover how this error was uncovered during the root cause analysis.

I. INTRODUCTION

Consolidated Edison Company of New York, Inc. (Con Edison) is one of the largest investor-owned utilities in the

world. Founded in 1823 as the New York Gas Light Company, Con Edison provides electric, gas, and steam services to over three million customers across 604 square miles of New York City (NYC) and Westchester County in New York [1], with a resident population exceeding nine million. Con Edison owns approximately 94,000 miles of underground cable and 34,000 miles of overhead conductors.

Because of its highly dense service territory, Con Edison operates one of the most complex electric systems in the world, providing highly reliable service.

System disturbances and interruptions caused by equipment failure, including those resulting from storms, floods, and even terrorism, can occur at any time. To provide reliable electric services, and fast restoration time, whenever system disturbances occurred, Con Edison must perform analysis of those disturbances swiftly and accurately. The Protection Support & Analysis team of Con Edison’s Protection & Controls Engineering department are the “guardian angels” of New York’s power system. The members of this team are always armed 24/7/365 to support the power system whenever a disturbance occurs, to analyze the event, perform root cause analysis, advise regarding isolation of failed system elements, assist restoration, perform corrective action plans, etc.

We have five (5) interesting power system events that involved protective relaying operations that we would like to share with the readers. In these five (5) events, we have 1) a transmission line protection mis-operation during an external fault due to inter-core coupling phenomenon within a GIS CT, 2) multiple protection zone mis-operations during an external fault with a legacy pilot wire scheme, 3) a series of power system faults introduced during the commissioning stage of a project, 4) undesired directional time overcurrent relay operation during a transformer load tap change (LTC) failure, and 5) an 87L scheme with 5+ years in-service history that mis-operated during an external fault three buses away.

II. EVENT #1 (87L MIS-OPERATED ON PHANTOM SECONDARY CURRENT)

In Summer of 2014, 345 kV (Transmission Line) Feeder 1 between Substation A and Substation B overtripped for a Phase-C fault on Transformer 1 at Substation C. The Transformer 1 tripped correctly for a Phase-C fault. Feeder 1

overtripped via the incorrect operation (Phase-B) of System #2's feeder current-differential relay system.

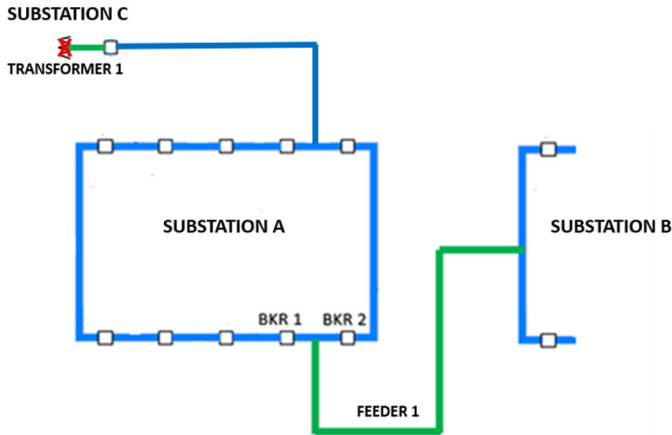


Figure 1a. Substation A arrangement

Analysis:

The fault on Transformer 1 was on phase C. The System #2 relaying on Feeder 1 mis-operated on phase B. The oscillography downloaded from the Feeder 1 relays shows elevated current on phase B at its Substation A end, but not at Substation B end. Thus, it appears to the line differential scheme that there is a fault on Feeder 1. The current should not be elevated at either end on phase B. It should only be elevated on phase C at both ends, equal magnitude and opposite phase, as through current flowing to the external fault on Transformer 1.

The relay fault recording in the below Figure 1b shows Feeder 1 "C" phase current contribution from Substation A and Substation B. There is no "B" phase current contribution from Substation B. The "B" phase current in Substation A increases drastically 3 cycles after the fault. The current increase duration is approximately 2 cycles. The increase in "B" phase current subsides immediately after the fault is cleared.

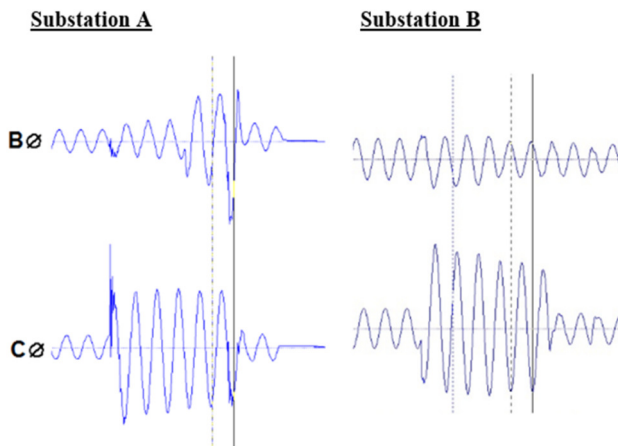


Figure 1b. Relay fault recording

The fault recording from the disturbance monitoring equipment (DME), at Substation A does not show elevated current on phase B of Feeder 1. It therefore doesn't agree with what the relays are seeing. The DME is taken from the feeder pothead CTs, whereas the relays are connected to the breaker CTs (breakers 1 and 2).

In recent history, there was another relay misoperation for Feeder 1 during an external Phase-B fault in Winter of 2013. Both of these relay mis-operations occurred only for "B" phase System #2 feeder current-differential relays at Substation A only. After the 2013 operation, a comparison of the relay oscillography and Substation A's DME records which was similar to the 2014 operation, had pointed to an AC circuit problem at substation A as the likely cause of the misoperation. Extensive relay and AC wiring testing failed to reveal any problems. Subsequent to the Summer 2014 misoperation, Inter-core coupling tests at the individual breaker CTs (Breaker 1 & 2) supplying the currents to Feeder 2 relays, revealed a problem at Breaker 1 Phase-B CTs. Compromised / incomplete insulation was found on the CT housing of Breaker 1 at Substation A on phase B. The cause of the problem was corrected by adding insulation to replace those gaps where insulation had been found missing. After these repairs, the CTs were then retested, with no indication of a problem.

Both Breaker 1 & 2 are installed within the GIS enclosures of Substation A, so the preliminary conclusion is that the GIS breaker CT inter-core coupling problem that led to the over-trips of Feeder 1 during external fault, causing a secondary current mismatch to the differential relay system, resulting in a misoperation during an external fault. This "phantom B" phase current increase discussed above is directly related to the Inter-core Coupling effect.

Inter-core Coupling Effect

The Inter-core coupling is caused when a conductive loop is formed around a few CTs stacked together. CT inter-core coupling occurs when the grounded circuit breaker enclosure is conductively connected to the grounded GIS SF6 bus enclosures. The breaker and bus enclosures are grounded at different points, and there must be a separation at the CT housing to prevent ground current (a portion of the return current from the external fault) from flowing through the CT core. The separation is insulated to prevent this, although the insulation need not be for more than a few hundred volts. So, there is insulation on the bus enclosure itself which prevents circulating ground current through the CT. And then there's also insulation inside the CT cover which prevents the metallic loop around the CT.

Figure 1c below shows the bus enclosure above and below the CTs is grounded. The top and bottom part of the bus enclosure is isolated near the CTs to prevent a continuous conductive loop that will cause inter-core coupling.

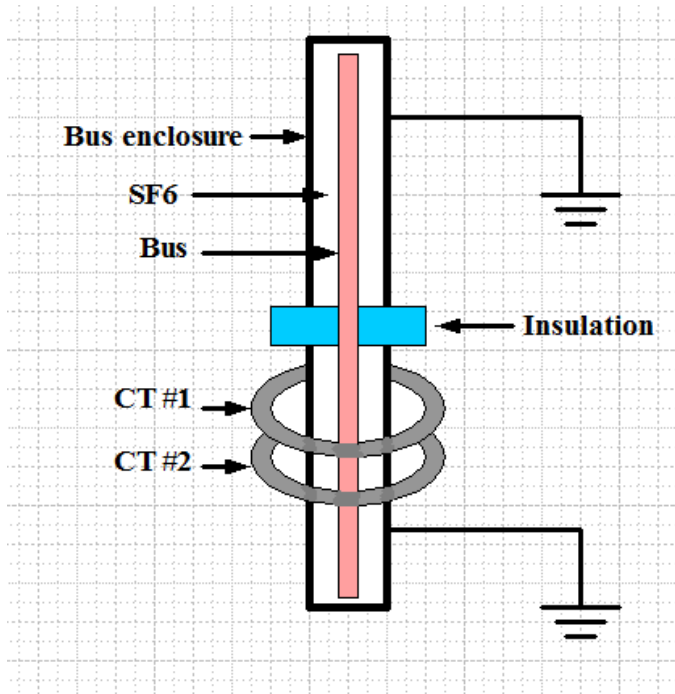


Figure 1c. Cross-section of Bus Enclosure

Figure 1d below shows detail of the CT enclosure with the top metallic cover. To prevent the conductive loop around the CTs, the top cover is insulated from the CT enclosure casing by rubber insulation (red). Figure 1e shows this insulation around the inner circle of the CT enclosure. Figure 1f shows the CT enclosure.

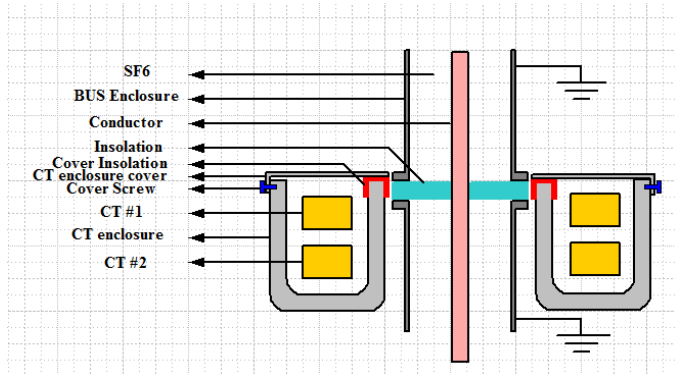


Figure 1d. Insulation between CT enclosure and top cover

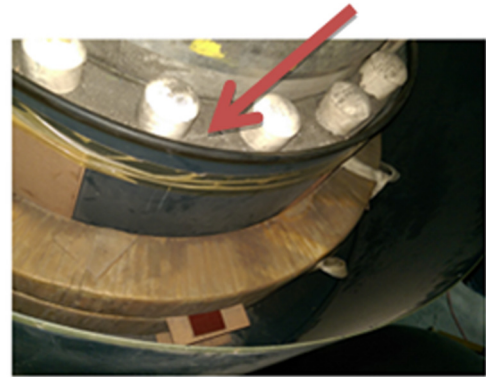


Figure 1e.



Figure 1f.

Figure 1g shows a small section of the insulation around the inner circle of the CT enclosure that was missing. There is a small air gap between the top CT enclosure cover and the casing where the insulation is missing. During normal operation this small air gap does not impact the CTs. But during an external ground fault, the ground potential rises and bridges this gap. This momentary action will complete the conductive loop around the CTs and cause inter – core coupling



Figure 1g.

Since the time that the repairs were made to the breaker 1 CT housing, Feeder 1 properly restrained from over-tripping during four external faults on the 345kV system in the electrical vicinity of Substation A.

- January 2015 – Phase B and C to Ground feeder fault
- June 2015– Phase A, B, and C feeder fault
- July 2015 – Phase B Shunt Reactor fault
- November 2015 - Phase A transformer fault
- March 2022 – Phase B transformer fault

Conclusion: The CT cover insulation and the integrity of the insulation on bus enclosure of both the breakers is important and if deteriorated could cause inter-core coupling effect and could lead to relay misoperation and mislead event analysis which can delay system restoration. It is recommended to check this insulation during the breaker diagnostic tests and perform CT Inter-core coupling check to avoid mis-operations in the future. If possible, CT housing covers within GIS installation can be replaced with non-conductive material type, such as fiberglass, this can minimize the chance to encounter inter-core coupling issue.

III. EVENT #2 (MULTI-RELAYS MIS-OPERATION ON SINGLE EXTERNAL FAULT)

In Winter of 2021, several 138kV breakers opened automatically at a 138kV substation, promoting System Operations to declare a Condition Yellow this involving three (transmission line) feeder mis-operations due to an adjacent bus section C phase fault on a circuit switcher. For the fault on the circuit switcher, the electromechanical bus differential relay 87 operated on C phase. This bus differential relay operated as per design to trip breakers A and B. As illustrated in figure 2a. This bus differential relay covers the bus section AB (between breakers A and B) up to the circuit switcher. The feeder and transformer associated with the circuit switcher had their own independent protection, which did not operate as designed because the circuit switcher was not within their protection zone. The backup protection for the bus section and the circuit switcher was provided by a digital ground overcurrent (51N) relay.

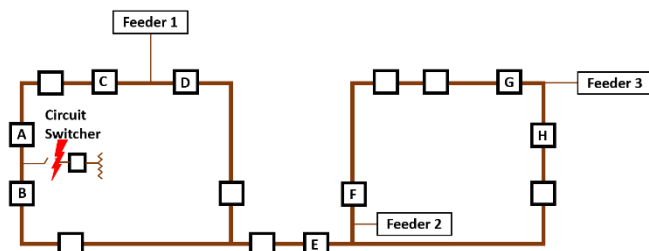


Figure 2a. Transmission line feeders' arrangement

This digital ground overcurrent (51N) relay for bus protection associated with the circuit switcher provided evidence of C phase to ground fault of about 40kA. As shown in figure 2b



Figure 2b. Neutral Current from Digital Relay

However, the three feeders that mis-operated during the event were equipped with electromechanical pilot wire relays. These three feeders experienced a misoperation at the local substation, while the remote end remained energized due to back-feed.

Working Principle of the Pilot Wire Scheme

Referencing to technical paper, “Ways to assure misoperation of electromechanical pilot-wire relays”, by Walter A. Elmore [4], the pilot wire scheme utilizes a symmetrical component "filter" that generates a single-phase output voltage that is dependent on the symmetrical component content of the three phase input currents. The filter was chosen to allow the system to respond very sensitively to ground faults and considerably less sensitively to phase faults. A filter configuration was chosen with positive- sequence and zero-sequence weighting factors to accomplish these ends. Figure 2c describes the nature of the filter that was selected.

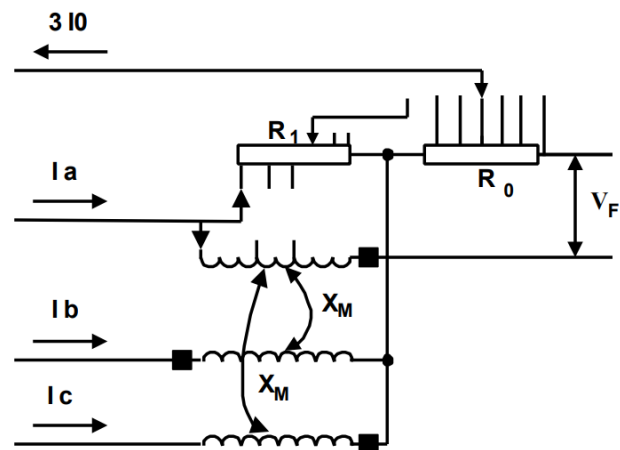


Figure 2c. Pilot Wire Relay

The output is shown as V_F . The output of the filter is connected to a saturating transformer that is internal to the relay and then to an external 4 / 1 step-up insulating transformer. The pilot-wires are then connected to the high-voltage terminals of the insulating transformer. Figure 2d. describes the elements that exist between the saturating transformer and the insulating transformer.

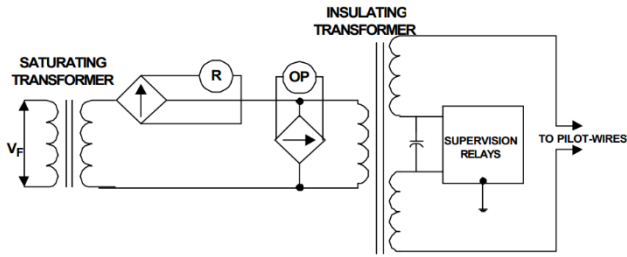


Figure 2d. Transmission line feeders' arrangement

An identical complement of components is applied at the other terminal, possibly many miles away. The pilot-wire itself is limited to 2000 ohms resistance and 1.5 microfarads, wire-to-wire.

The intent of this relaying system was to accommodate short lines for which distance relays were inadequate because of their imprecision in identifying fault location on short lines.

Investigative Testing and Findings

For this particular event, feeder protection is typically ensured by two independent systems of protection, as per design basis. Consequently, for Feeder 1, the System #1 pilot wire relay mis-operated, while its System #2 pilot wire relay did not. In the case of Feeder 2, its System #2 pilot wire relay mis-operated, while its System #1 pilot wire relay did not. Similarly, for Feeder 3, its System #2 pilot wire relay mis-operated, and its System #1 digital line current differential relay did not mis-operate.

Thorough investigative testing was performed to find the root cause of these trip outs. All the feeder relays that incorrectly operated during the event were requested for functional testing and calibration which revealed the following findings:

1. The cause of the Feeder 1 misoperation was due to the pilot wire relay being out of calibration. During calibration of System#1 pilot wire relay, it was found that the A phase to Neutral current pickup and dropout test failed on restraint mode. Additionally, the historical data from this particular relay suggested repeated incorrect operations due to similar calibration issues in the past.
2. For the Feeder 2 misoperation, it was initially suspected that the pilot wire relay was out of calibration. A comprehensive test of the relays (included the pilot wire monitoring relays) and its associated pilot wire yielded satisfactory results. In reference to the technical paper "Ways to Assure Misoperation of Electromechanical Pilot-Wire Relays" by Walter A. Emore [4], a comprehensive process of elimination was employed for this pilot wire relay. The evaluation included verifying the following conditions: reversed pilot wires, differing settings at the two terminals, varying CT ratios and CT

accuracy classes at the terminals, resistance and capacitance of the pilot wires exceeding specified limits, phase swapping, ground-mat voltage rise issues, induced voltage complications, different relay designs, different ratio insulating transformers at the terminals, currents being shorted at one end, pilot wires being open-circuited or shorted, failure to use insulating barriers during in-service tests, and failure to use exciting capacitors with neutralizing reactors. All these factors were examined and found to be satisfactory, except for the ground-mat voltage rise issue, which was identified as the root cause of the event. Ground-mat voltage rise in pilot wire relays refers to the increase in voltage potential between the ground grid and the surrounding earth. This can occur due to factors like elevation differences, soil resistivity, induced voltages. Higher elevations often have drier soil and rockier terrain, leading to increase in ground resistance. This voltage rise can cause unintended current flow through the pilot wires, potentially resulting in relay misoperation, as illustrated in figure 2e and figure 2f. Proper grounding practices and regular monitoring are essential to mitigate these issues and ensure reliable relay operation.

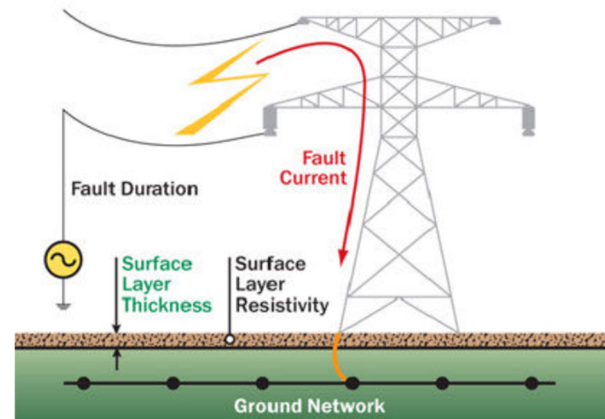


Figure 2e. Ground Potential Rise

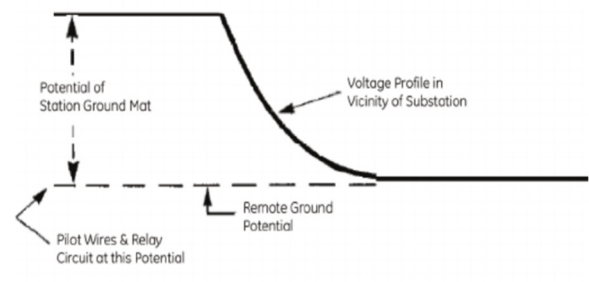


Figure 2f. Ground Mat Voltage Rise

In 2022 where an external SLGF took place on the adjacent element, with a breaker failure operation, demonstrated that Feeder 2's pilot wire was able to transfer trip correctly during an external fault, this

indicated that the pilot wire medium itself for Feeder 2 was in acceptable condition. Certain portions of this substation's ground grid were known as ineffective, due to corrosion. Therefore, the ground grid reinforcement project was in place before the misoperation. Additionally, the two ends of the feeder were at different topographical elevation levels. One end of the feeder is located at a higher elevation with rock ledge while the other end is at sea level, as shown in figure 2g. In other words, higher elevation results in increase ground resistance due to the drier soil and rockier terrain.



Figure 2g. Stations associated with Feeder 2 with elevation

This investigation determined that during the 2021 misoperation event, the momentary rise in ground mat voltage affected the pilot-wires and/or the relay case of the supervisory relay during the external fault, and caused a false trip (reference to “Ground-Mat Voltage Rise” problem in [4]).

3. Right after the misoperation of Feeder 3, this pilot wire scheme was replaced with modern microprocessor-based line current differential relay, with digital communication, as part of a planned relay replacement program. It is highly suspected that Feeder 3's legacy pilot wire relay was out of calibration, similar to Feeder 1's.

Corrective Actions

Immediate Measures

To address the immediate impacts of the misoperation, the following actions were undertaken:

1. The pilot wire relay associated with Feeder 1 was recalibrated as per the specifications. It was decided to replace the pilot wire scheme with microprocessor-based line current differential scheme in the near future. However as a quick fix, calibration of the

System#1 pilot wire relay was performed, specifically the A phase to N current pickup and dropout test on the restraint coil, which failed initially. To perform the Restraint Mode Bias Pickup and Dropout Test according to the pilot wire calibration instructions, terminals 18-19 on the relay were jumped. The current was ramped up to 30 Amps (A-N) and then ramped back down to zero Amps, after which the jumper was removed post-bias. A set of restraint taps are located on the front of the relay near the polar unit. These taps are the maximum and minimum restraint taps of the relay. The initial test results indicated a margin of error of 31% on ramp 1 and 51% on ramp 2. After several iterations, the acceptable margin of error was reduced to 2% on ramp 1 and 11.43% on ramp 2. In reference to the HCB Pilot Wire Relay System, ABB Instruction Leaflet. IL:41-971.2H [5]

2. The pilot wires relays for Feeder 2 and Feeder 3 were replaced with microprocessor-based relays with new modern communication channels in September 2022 and March 2022, respectively.

Long-Term Plans

The pilot wires and their respective relays had been in the system since 1940s and thus required frequent relay calibrations due to their deterioration over time. In addition, modern microprocessor-based 87L relays along with reliable and redundant fiber optic channels provide excellent security and dependability to short line protection. To prevent future occurrences, a comprehensive relay modification program was initiated, aiming to replace all legacy pilot wire relays system wide.

Conclusion

The relay misoperation at the substation highlighted significant vulnerabilities in existing protection systems. Legacy pilot wire relays, combined with susceptibility to transient events, contributed to the disruptions. Immediate corrective actions, such as relay recalibration and replacement with modern microprocessor-based relays, addressed short-term risks. Moreover, the comprehensive relay modification program ensures improved system reliability and better protection against similar faults in the future. This case study underscores the critical importance of proactive system upgrades in maintaining the integrity of critical infrastructure.

IV. EVENT 3 (A SERIES OF SYSTEM FAULTS CAUSED BY AN “UNDEAD” IN THE POWER SYSTEM)

In Spring of 2023, 345kV Transmission Line C1 between Substation R Breakers R6 and R7 and Substation M Breakers M4 and M9 tripped. Breakers R7, M4, and M9 were tripped while Breaker R6 was previously opened. At the time of the trip, the operator at Substation R was on orders associated with commissioning of new 138kV Transmission Line C21, which connects to the 138kV Phase Anger Regulator PAR5 and then to the 345kV/138kV Auto Transformer TR5 between Breaker R5 and R6 adjacent to Line C1 as shown in Figure 3a.

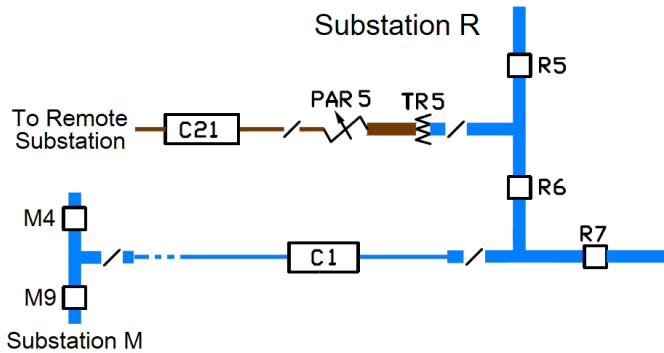


Figure 3a. Topology of the Affected Areas

Both Breakers R5 and R6 were previously opened, and the remote terminal of Line C21 was also opened. As a result, Line C21, PAR5 and TR5 were all supposed to be deenergized. The operator at Substation R was trying to exercise a set of three phase disconnect switches associated with Line C21 next to PAR5, and reported seeing arcing at the disconnect switch of Line C21 right before the 345kV Line C1 was tripped open.

Relay targets reported that Line C1 was tripped by both systems of line current differential relays. PAR differential relays and auto transformer differential relays at Substation R also showed trip targets. Field reports showed that the Phase A surge arrester installed between TR5 and PAR5 had failed, and Breaker R6 showed a Phase C fault at Line C1 side.

Relay oscillography showed that prior to the event, voltages were presented at the auto transformer TR5 and the phase angle regulator PAR5, with Phase A and Phase B both at 0.5 pu in phase with each other, and Phase C at 1 pu about 180 degrees out of phase with Phase A & B, even though whole section was supposed to be deenergized. Phase to phase voltage, V_{ab} was used to indicate whether the section was live or dead. Since Phase A and Phase B voltages were in phase with the same magnitude, V_{ab} was shown at 0V. As a result, operators were not aware the section was live.

Later investigation found that a loose nut caused Phase C of Breaker R6 to be connected after the breaker was switched open hours prior to the event. TR5 and PAR5 were kept energized through Phase C of Breaker R6 until the trip-out. Line C21 was deenergized since the disconnect switch and the remote terminal were both open.

Auto transformer TR5 has a delta connected tertiary windings. When energizing through only Phase C of Breaker R6, the 1 pu voltage V_c was induced to the tertiary windings as

shown in Figure 3b. With delta connection, V_c was equal to negative of the sum of V_a plus V_b . Thus, V_a and V_b both had the magnitude of 0.5 pu and 180 degrees out of phase to V_c . The two voltages were then induced from the tertiary windings back to the primary and secondary windings of TR5. Figure 3c shows the voltages at Line C21 captured by the relay oscillography.

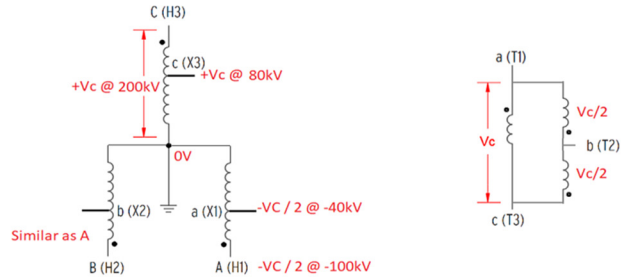


Figure 3b. Voltage Induction due to Delta Tertiary Windings

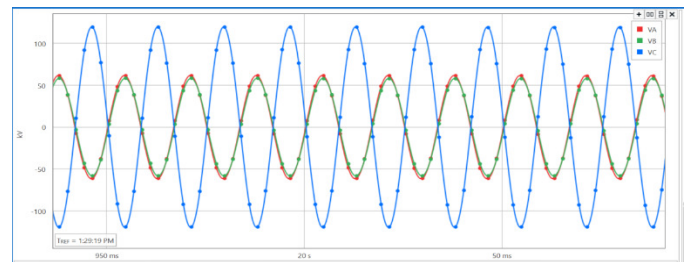


Figure 3c. Voltages Captured at Line C21 Prior to the Arcing

Prior to the event, V_{ab} at the disconnect switch of Line C21 was at about 0V while V_{bc} was at about 1.5 pu. Phase B was the middle phase and the other two were the outer phases. When the operator exercised the disconnect switch, Line C21 was inadvertently energized. The charging current with the potential difference of 1.5 pu caused arcing, between phase B and phase C, and caused a temporary short between the two phases. That forced V_b to be in phase to V_c with similar magnitude of 1 pu as shown in Figure 3d.

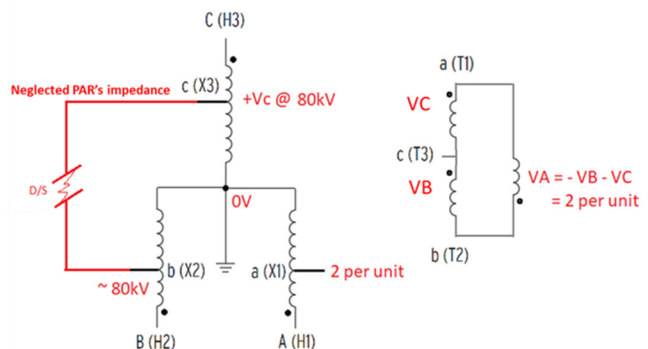


Figure 3d. New Voltage Induction during Arcing

The new voltages were induced back to the tertiary windings of the auto transformer. Since V_a was equal to the negative of the sum of V_b plus V_c within the delta windings, V_a at that moment had the magnitude of 2 pu and 180 degrees out of phase. With induction back to primary and secondary windings

at Phase A, 2 pu voltage was presented at the surge arrester, causing it to fail with a Phase A to ground fault. Figure 3e shows the voltages at Line C21 captured by the relay oscillography during the arcing.

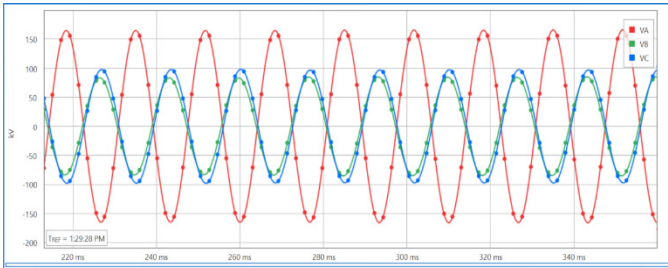


Figure 3e. Voltages Captured at Line C21 During Arcing

Relay oscillography also captured current waveforms around TR5 and PAR5 during surge arrester failure. Figure 3f illustrates the current flows in the section during the event.

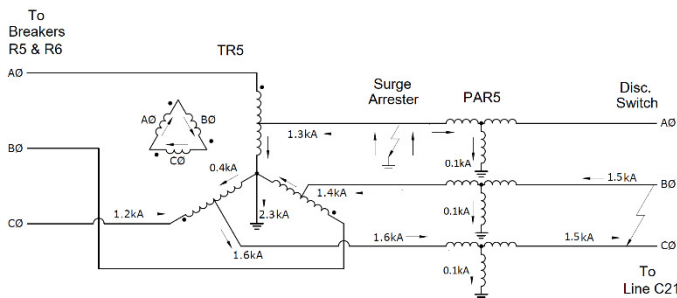


Figure 3f. Current Flow during Phase A Surge Arrester Failure

Even though both the transformer and PAR differential relays tripped during the surge arrester failure, Breakers R5 and R6 were already opened. The fault could not be interrupted and continued to be fed through phase C of Breaker R6. A few cycles later, phase C of Breaker R6 failed. That resulted in a Phase C to ground fault at the source side of Breaker R6 that fell into the protection zone of the adjacent Transmission Line C1. Line C1 therefore was tripped open. The fault currents at Line C1 during the fault were shown in Figure 3g.

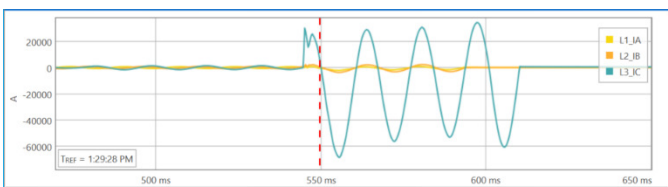


Figure 3g. Fault Currents at Line C1 during Breaker 6R Fault

Relays protecting the 138kV Transmission Line C21 did not trip during the event, even though the arcing occurred at the disconnect switch that fell into the protection zone of Line C21. Line C21 was protected by two systems of differential elements and backup by distance elements.

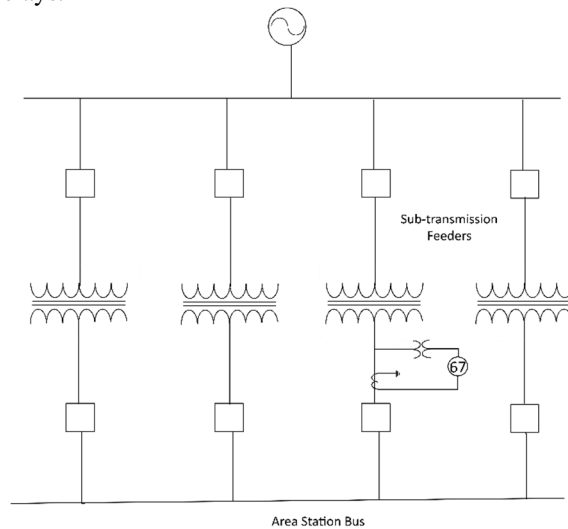
The differential elements were supervised by phase instantaneous overcurrent elements (as a fault detector) while the distance elements were supervised by loss of potential logics. The fault detectors were set at 2.4kA that was higher than the 1.5kA fault current during the arcing. Loss of potential logic was asserted prior to the arcing. As a result, the relays for

Line C21 did not trip at all. One corrective action plan was to lower the pickup of the fault detectors from 2.4kA to below 1.5kA.

One issue of this event was using phase to phase voltage, V_{ab} for system monitoring that gave the incorrect indication that the section between Breakers R5 and R6 at Substation R was dead while it was actually live. It was an inherited old design, and it would be safer and more reliable to use all three phase voltages for system monitoring.

V. EVENT #4 (A BAD DIRECTION DETERMINATION CAUSED BY TRANSFORMER LTC FAILURE)

In Summer of 2023, 13kV Substation low side Breakers tripped. As a result, the substation transformer became unavailable to the system. A CMVM (contact-making voltmeter for load tap changer operation) issue caused the transformer's tap changer to go to 16L, the potential differences between the transformer & its adjacent transformers caused circulating current between them. A high-level arrangement of an area (distribution) substation is shown in Figure 4a. The transformers are running in parallel, causing the circulating current. The relay targets show one of the two systems of phase directional overcurrent element (67) operated that are intended to clear back-feed during phase-to-phase and three-phase faults on the 138 kV sub-transmission feeder. These two protection systems are supplied by the same 13kV PTs but by different 13kV CTs. Two systems of directional phase overcurrent elements are identical, residing within separate microprocessor relays.



Figure

4a. High level arrangement of an area substation showing CTs and PTs for the directional element that operated.

The popular 90° connected phase directional element is explained in [2]. The operating and polarizing quantities for each of the phase elements are chosen so that polarizing quantity is based on the unfaulted phases shown in Table 4a below (quadrature polarized).

Table 4a. Phase Directional Element inputs

Phase	Operating Quantity (I _{OP})	Polarizing Quantity (V _{POL})
A	I _A	V _{POLA} =V _{BC}
B	I _B	V _{POLB} =V _{CA}
C	I _C	V _{POLC} =V _{AB}

The torque (TPHASE) calculations for each 90° connected phase directional element are presented by the following equations:

$$T_A = |V_{BC}| \cdot |I_A| \cdot \cos(< V_{BC} - < I_A)$$

$$T_B = |V_{CA}| \cdot |I_B| \cdot \cos(< V_{CA} - < I_B)$$

$$T_C = |V_{AB}| \cdot |I_C| \cdot \cos(< V_{AB} - < I_C)$$

where:

I_A, I_B, I_C = A-, B-, and C-phase currents, respectively. V_A, V_B, V_C = A-, B-, and C-phase voltages, respectively. V_{AB}, V_{BC}, V_{CA} = voltage difference between respective phases.

If the torque sign is positive, each directional element declares a forward fault condition and if the torque sign is negative, a reverse fault condition.

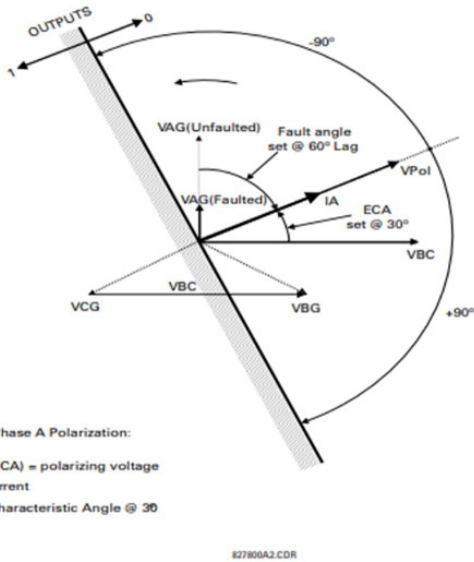


Figure 4b. Direction Polarization for Phase A **Error! Reference source not found.**

Figure 4b shows the quadrature polarization method. If I_A lies in the reverse region, output will be 1 and the directional elements will be blocked from tripping.

During the event, the relay oscillography captured the current right above the 67-element’s overcurrent element pickup level and moved to the forward region as shown in Figure 4c by the System #1 relay. The blue line represents the polarizing voltage (aka: max torque angle) and the red line represents I_A. The region above the gray line represents the forward region (V_{Pol}±90°). Therefore, the directional element operated, and it tripped the 13kV breakers, by design. By comparing the phase current angle to the corresponding polarizing voltage angle, all three phases current angles were

on the edge for the relay to declare either forward or backward direction. The circulating current due to the CMVM issue stayed above the 67-element’s overcurrent element pickup and the angle of the current fell right at the edge for the System #1 relay to declare forward direction on phase A. Therefore, in this case, phase A of the System #1 relay declared forward and tripped. This is the correct operation but undesired under the CMVM issue conditions.

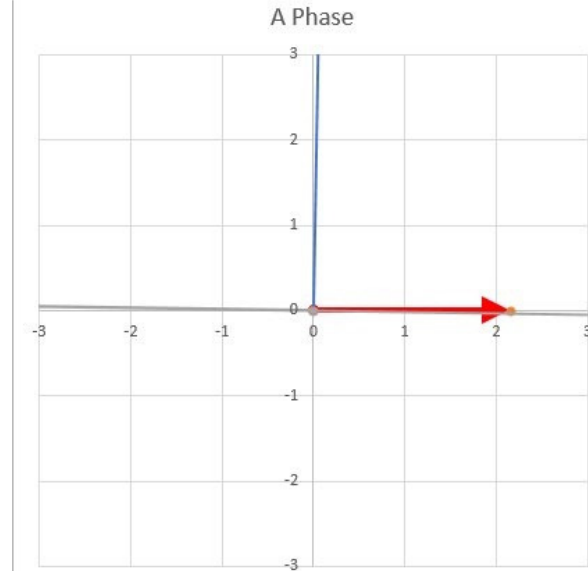


Figure 4c. Directional Element for phase A

The corrective action plan (CAP) to enhance security was to increase the time-overcurrent (TOC) element’s pickup after performing fault studies and increase element characteristic angle, ECA (or RCA) to account for this corner case. Figure 4d. shows the directional element after the CAP. Note that the direction is reversed, and the directional element is blocked. The new settings under the CAP can tolerate higher MVAR back-feed.

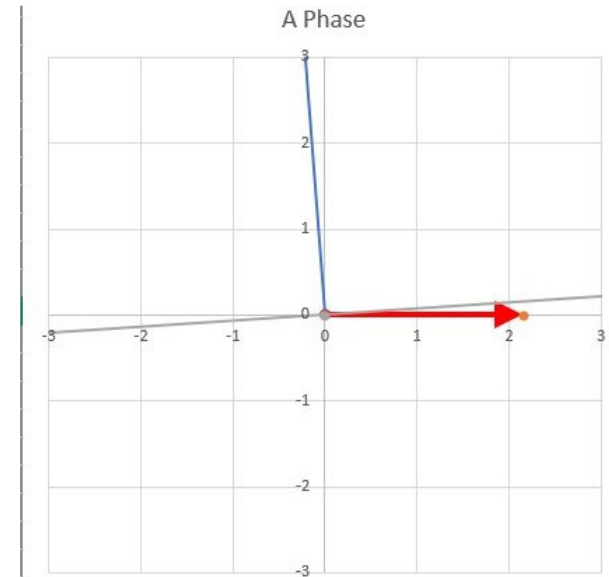


Figure 4d. Directional Element for phase A after CAP

The positive sequence directional element is another method where positive sequence voltage is used as a reference [2]. If the positive sequence voltage angle is within 120° to 300° , the direction is declared as reverse. Similar to the quadrature polarizing method (where the forward and reverse plane are divided into 180° each), the directional element for this method can still be asserted under reactive power back feed condition. As shown in Figure 4e below, the positive sequence directional element would have seen the positive sequence voltage angle in the reverse plane based on the signals collected during the trip-out as shown by assertion of Z1R. Therefore, the positive sequence directional element is more secure and does not operate during the event. The main difference with quadrature polarizing method for positive sequence directional elements is the absence of ECA angle. However, in theory, under three phase balance load condition, the phase directional element has an equivalent of ECA setting of 60° . This phase sequence directional element could also tolerate higher MVAR backfeed (more than the CAP settings). However, for both phase-phase and phase-phase-ground unbalanced fault types, only positive and negative-sequence quantities are available. Therefore, for unbalanced fault directional element, negative-sequence quantities remain as viable inputs, since positive-sequence load quantities mislead a directional element for unbalanced faults. Therefore, for dependability and security, both positive and negative sequence directional elements are preferred over traditional collection of three-phase directional elements [2].

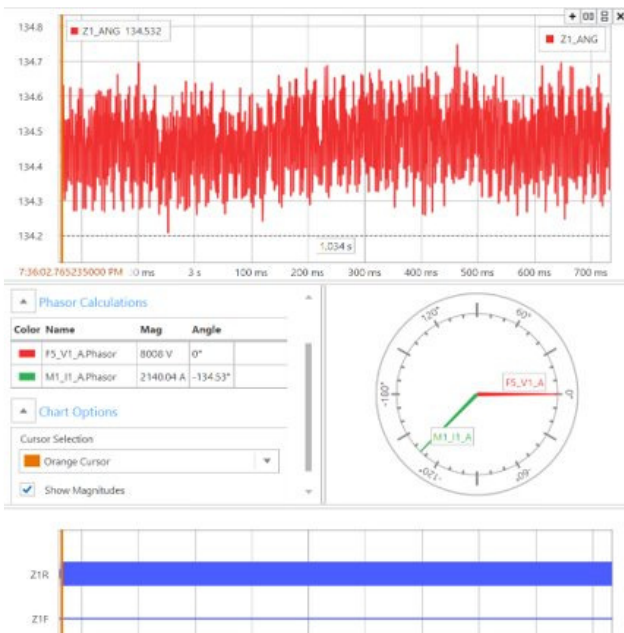


Figure 4e. Positive sequence Directional Element response to the event

VI. EVENT #5 (MISOPERATION OF A 5 YEARS OLD 87L SCHEME ON EXTERNAL FAULT 3-BUSES AWAY)

In Summer of 2024, while removing Substation H Shunt Reactor R3 from service, Circuit Switch CS-3 failed and caused a B-C Phases fault at Circuit Switch CS-3. Subsequently, Substation H 138kV Bus Section 3 and associated outlet 138kV Transmission Line E3 to Substation G tripped. Breakers H3 and H4 were tripped at 138kV Substation H, and Breakers G2 and G3 were tripped at 345kV substation G. In addition, 345kV transmission Line E1 between Substation F and Substation D tripped. Breakers F1 and F2 were tripped at 345kV Substation F and Breakers D1 and D2 were tripped at 345kV Substation D.

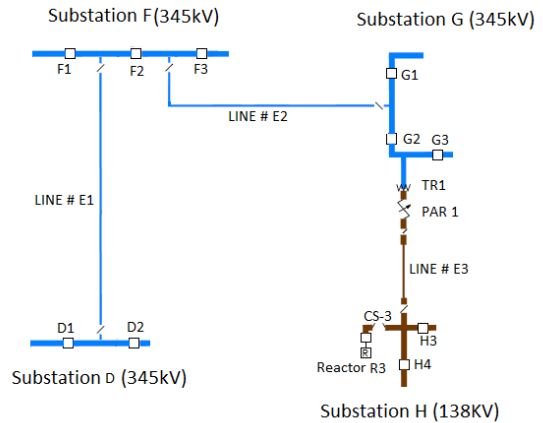


Figure 5a: System One-line diagram

138kV Transmission Line E3 is connected to the same Bus Section as the Reactor R3 at Substation H. 138kV Transmission Line E3 connects to the 138kV Phase Anger Regulator PAR1 and then to the 345kV/138kV Auto transformer TR1 at 345kV Substation G. 345kV Transmission Line E2 is connected between 345kV Substations G and F. Also, 345kV Transmission Line E1 is connected between 345kV Substations F and D.

Damage was found on Substation H 138kV Circuit Switch CS-3 B and C phases. Relay protection for the 138kV Transmission Line E3 operated correctly to clear the B-C phases fault at Circuit Switch CS-3. Relay targets reported that Transmission Line E3 was tripped by both Systems of line current differential schemes.

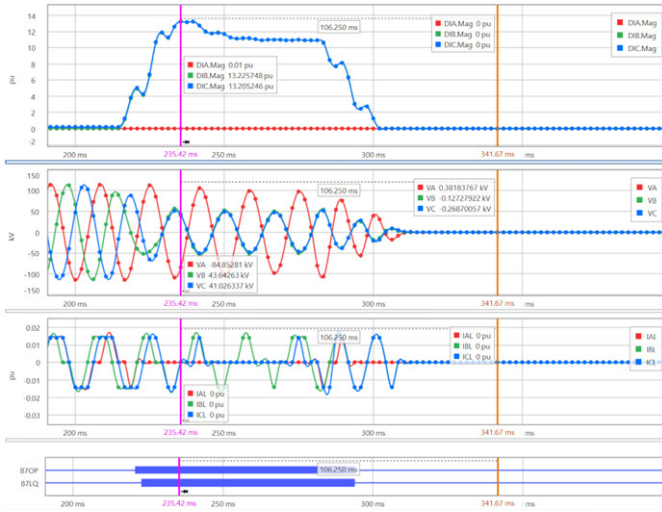


Figure 5b: Substation G Line # E3 Relay Event Record

Relay targets report 345kV Transmission Line E1 was overtripped by both Systems of line current differential schemes via their respective negative sequence current differential element (87LQ).

Relay oscillography files indicated relays associated with 345kV Transmission Line E1 exhibited steady differential current prior to the event, indicating a pre-existing issue with the protection systems. During the Circuit Switch CS-3 fault at Substation H, all phases differential current elevated. The 87LQ element was as high as 0.67 PU during fault at Substation H Circuit Switch CS-3. The relay Pickup setting for the 87LQ was set at 0.35 PU.

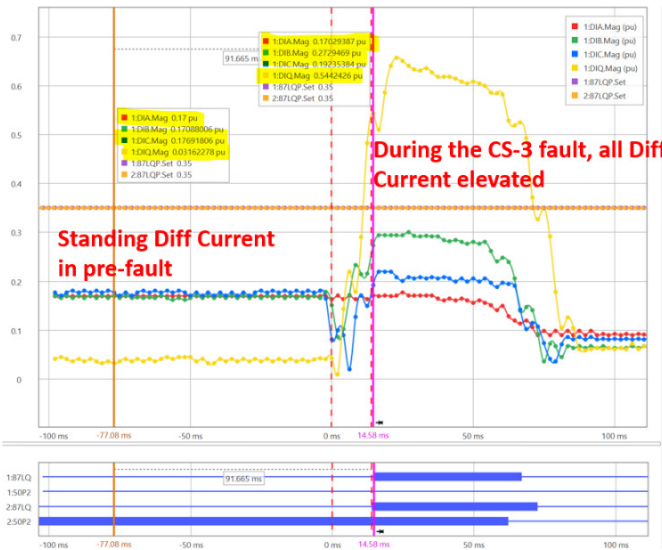


Figure 5c: Substation F Line # E1 Relay Event Record

Both Station D and F are ring bus configuration, with their relays set up as two (2) terminals line current differential scheme. Each terminal's relays have dual sets of three phase current inputs, each set of current inputs are fed from each of

their respective breakers' CTs. Per Substation D Line # E1's relay event file, we can see both negative sequence currents (I2W & I2X) from its respective breakers' CTs lead their respective negative sequence voltage (V2Y) about 151 degrees in Figure 5d. This supported the system fault current flow where we would expect Substation D would supply fault current to Substation F via Line # E1.

V2 & I2 Relationship at Substation D(Flowing Out)



Figure 5d: V2 and I2 Relationship at Substation D Line # E1 from relay Event Record

Since it was a thru-fault for Line #E1, for Substation F, we would expect to see both its breakers' currents to be 180 degree out of phase with respect to Substation D's currents, with the same magnitude. But per Substation F Line #E1's relay event file, we only can see one of the negative sequence current (I2X) lags its respective negative sequence voltage (V2Y), but realizing its other negative sequence current (I2W) LEADs its respective negative sequence voltage about 98 degree in Figure 5f. The absolute summation of the negative sequence currents of the local matched with its remote's. This is an evidence of the IW terminals three phase currents at Substation F Line #E1 relays had reversed polarity connection.

V2 & I2 Relationship at Substation F (Flowing In)

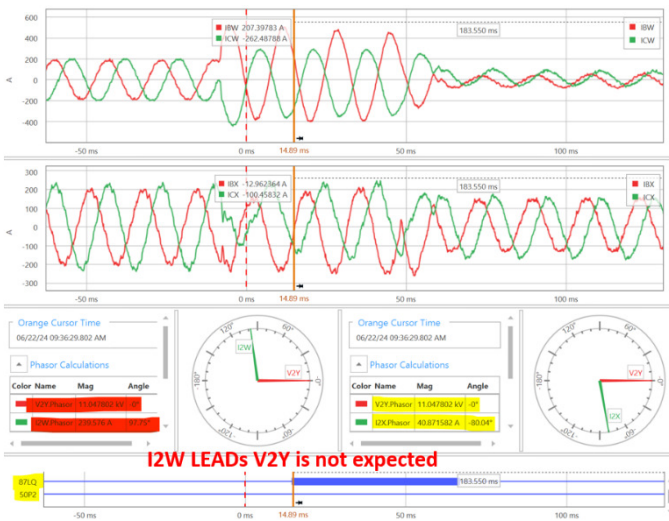


Figure 5f: V2 and I2 Relationship at Substation F Line # E1 from Relay Event Record

Further analysis indicated the current transformer Inputs from Substation F Breaker F1 to the Transmission Line #E1’s System 1 & 2’s protection relays were connected to the incorrect polarity, explaining the pre-existing differential currents and the differential relays mis-operations during an external fault.

Substation F breaker F1 was recently upgraded and put back in service less than a month. Protection drawings issued for construction of the Substation F Breaker F1 replacement revealed the introduction of the polarity error into the system. The One line Relay schematic was issued, showing the correct polarity and connection. However, the 3-Line AC wiring diagram drawings indicated incorrect polarity connections as shown in Figure 5g. Breaker F1 CTs wiring to both system protection relays winding polarity side were wrong (using the non-polarity) side of the new breaker F1 CTs.

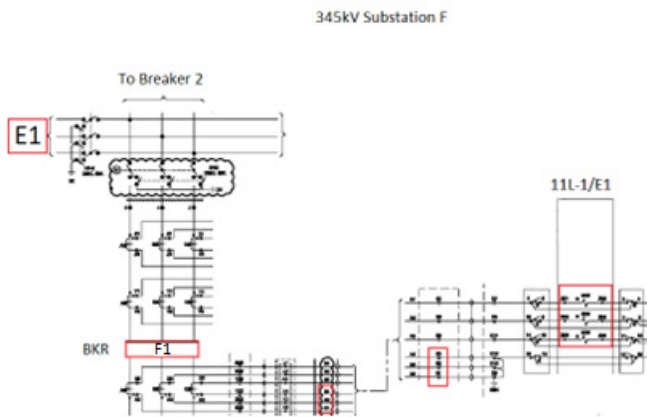


Figure 5g: 3 Line AC wiring diagram for 1st line Protection relay for Transmission Line E1

The error was on the 3-Line AC schematic drawing. The drawing was designed in compliance with the design procedure, and a follow-up design supervisor and checker was completed. Subsequently, in compliance with the Design standard, the 3-Line AC schematic was sent to the Relay Protection Engineer for approval, and the Relay Protection Engineer approved the preliminary 3-Line AC schematic. Before sending the drawings for formal approval in the drawing system, the design team noticed that they had carried a nomenclature from the old CT and decided to change it. Unfortunately, this nomenclature change caused an error in the CT polarity wiring. The Relay Protection Engineer did not have the opportunity for a final review/approval as the drawing was not transmitted in drawing system due to an issued with the title.

Lesson Learns

Never overlook an in-kind replacement, a simple disconnect and re-connect has to verify is the same as before. Although these digital relays were already commissioned, but these digital relays are excellent tools for us to use to find error, for example, performing load/differential currents reading using the relay’s front display or event trigger. Following company internal work process is a key to minimize chance of error. Engineering teams among themselves always communicate with each other’s for any changes from their respective team and perform proper peer checking to improve engineering design quality.

Corrective Actions in Design

Introduce an additional review for all connections involving CTs. Until a small team of “experts” is established to handle this responsibility, the Design managers will peer review all 3-Line AC schematics. Standardize the title for 3-Line AC schematics. Establish a campaign to educate designers and engineers to identify errors in CT polarity wiring.

Corrective Actions in Test and Commissioning

Leverage the Commissioning Group prior to the start of projects to clearly identify the method of performing commissioning testing, including primary injection. This coordination with commissioning engineers and supervision will add an additional line of defense in the process to prevent events. Improve the Primary Injection procedure to provide clear guidance to the Commissioning group regarding primary injection setups are appropriate based on scheduled work. When performing load readings for Line Differential relays, change the process to require Differential Load reading.

VII. SPECIAL ACKNOWLEDGEMENTS

All these five (5) events have one thing in common, collaborative joint efforts between the Engineering teams and the Operations teams. This included those individuals that retired or have transitioned to different roles within or outside of Con Edison. All these individuals contributed their experiences, knowledges, and recommendations to identify the root causes, and solutions, so the latter can learn all these problems, reinforce the standards, procedures and best practices to minimize these undesired relay misoperation.

VIII. CONCLUSION

All the problems/challenges that were discussed in this paper, may or may not be common in certain electric utility, depends on its geographical location, the arrangement of the power system element, protection system design philosophy, operational practice and many more. We hope the readers can learn the “stories” that we shared in our paper, by knowing how to identify the problem and its root cause, technique to analysis them, short/long term solutions, and building comprehensive standards, procedures and best practices to minimize all these issue, at last of course continuous improvement.

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BIOGRAPHIES

Ed W. Chen graduated from City University of New York with a Bachelor of Science in Electrical Engineering Science and from Worcester Polytechnic Institute with a Master of Science in Electrical and Computer Engineering. Ed joined National Grid New York in 2010. In 2012, he became a relay protection engineer in their protection analysis and relay project engineering groups. In 2016, Ed joined Consolidated Edison Company of New York, Inc. and continues to work there as a relay protection engineer. In 2022, Ed was promoted to the section manager of Protection Support & Analysis in Consolidated Edison Company of New York, Inc. Ed is a registered Professional Engineer in the state of New York.

Jianzhuang Huang received Bachelor of Science in Computer Engineering, Master of Science and Ph.D. degrees in Electrical Engineering from Binghamton University, State University of New York. He first worked as a power electronic engineer in 2007 at Endicott Interconnect Technology Inc. He then joined New York State Electric & Gas in 2013 as a power system protection engineer, and transferred to Consolidated Edison Company of New York, Inc. in 2017 as a relay protection engineer. He joined the group of Protection Support & Analysis in Consolidated Edison Company of New York, Inc. in 2022 where he focused on event analysis. Jianzhuang Huang is a registered Professional Engineer in the state of New York.

Pallavi Kuchikulla received Bachelor of Science in Electronics and Communications from Osmania University, India, and a Master of Science in Electrical Engineering from New Jersey Institute of Technology. She joined

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Naresh Malla received the B.E. degree in electrical engineering from Pulchowk Campus, Kathmandu, Nepal, in 2010, and the M.S. degree in electrical engineering and computer science from South Dakota State University, Brookings, SD, USA, in 2017. His current role is Senior Engineer with Consolidated Edison Company of New York. His current research interests include protection systems, machine learning, computational intelligence, adaptive control for power-electronic devices, smart grid, resilience of electric power delivery systems, and electric power systems stability and control. Naresh is a registered Professional Engineer in the state of Washington.

Khawla Munawwer received a Bachelor of Science degree in Electronic Engineering from Sir Syed University of Engineering and Technology in 2015 and a master's degree in electrical engineering from City University of New York in 2022. Prior to joining Con Edison Khawla worked as an Electrical Engineer contractor in the Field and Equipment Engineering group for Con Edison, where she worked as a lead discipline Engineer on multiple relay upgrade projects. She joined Con Edison in 2019 and is currently working as a Senior Engineer in the Protection Support and Analysis group, focusing on event analysis.

Lizhong Situ received both the Master of Science and Bachelor of Science in Electrical Engineering from State University of New York at Stony Brook. He joined Con Edison in 2019 as Senior Engineer at the Relay Protection Engineering section and worked on many challenging projects. Before joining Con Edison, He worked as Lead System Protection & Controls Engineer at New York State Electric and Gas for the last seven years. He also previously worked for First Energy Corporation, New Jersey as Protection and Reliability Engineer.

Dan Taft received a Bachelor of Engineering degree in Electrical Engineering from Stevens Institute of Technology in 1979 and a Master of Engineering degree in Electric Power Engineering from Rensselaer Polytechnic Institute in 1990. He started in the field of protective relaying at General Electric in Philadelphia and later worked on ground fault interrupters and surge suppressors at Hubbell in Bridgeport, Connecticut. He joined Con Edison in 1990, working again in protective relaying, before becoming a Senior System Operator and a manager in Transmission Planning. From 2009 to 2011 he worked in the Office of Electric Reliability for the Federal Energy Regulatory Commission in Washington. Returning to Con Edison, he became manager of the Operations Analysis Group in the Control Center. Since 2013 he has been Chief of Protection and Controls Engineering. He is a Professional Engineer in the State of New York.