

# A Case Study: Pilot Protection Misoperations Due to Transmission Line Switching

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# A Case Study: Pilot Protection Misoperations Due to Transmission Line Switching

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**Abstract**—Several transmission protection misoperations have occurred because of the operation of pilot protection schemes during transmission line switching. Because the pole-scan duration for transmission in-line load-break disconnect switches can last anywhere from cycles to seconds, the increased zero-sequence current can cause the misoperation of ground-distance elements and ground overcurrent elements used in the pilot protection scheme. Through many decades of operational experience, transmission utilities have developed various solutions (often compromising on speed or sensitivity) to prevent pilot protection misoperations during transmission line switching. A robust solution that allows pilot protection schemes to differentiate between a true transmission line fault and transmission line switching, while still maintaining speed and sensitivity, would help further improve reliability.

In this paper, we present many solutions implemented by various utilities and compare the solutions against real-world events.

## I. INTRODUCTION

Many subtransmission and transmission systems, often at the 69 kV and 138 kV level, are designed with several tapped distribution transformers along the transmission line. Because of economics, the high-voltage side of these tapped transformers is rarely designed with a three-breaker ring bus that can isolate one or both sections of the upstream transmission line. For sectionalizing, an economical alternative is to use in-line load-break disconnect switches, which are designed to interrupt lower levels of current. Utilities often use these switches for sectionalizing portions of the transmission line to minimize outages to tapped distribution transformers during transmission line maintenance activities.

Transmission line switching increases the flexibility and reliability of the electric power system. However, poorly maintained or out-of-alignment switch equipment can lead to unbalanced system conditions that can last for a few cycles or more. The unbalance caused by line switching is typically higher than the natural system unbalance. These unbalanced system conditions can challenge the security of sensitively set protection elements, which may lead to undesired operations. The risk is primarily associated with pilot schemes on transmission lines with or adjacent to in-line load-break switches. Although sensitively set ground overcurrent elements are more susceptible to misoperating because of transmission line switching, ground mho and quadrilateral ground elements can also pose a risk of misoperating, especially when the line is heavily loaded.

The pole switching of any three-phase transmission switching device typically does not operate simultaneously. While transmission circuit breakers normally have a pole-scan duration of less than 1 cycle [1], the pole-scan duration can be in seconds for older models of transmission in-line load-break disconnect switches that may not be sufficiently maintained. Fig. 1 shows a real-world event where the switching unbalance lasts for 12 cycles. One utility has reported pole scan lasting as long as 3 seconds (180 cycles).

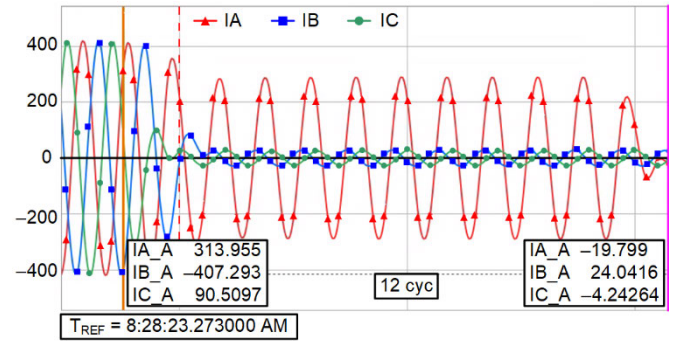


Fig. 1. Real-world event for switching unbalance of a 12-cycle duration.

Typical load-break disconnect switches are designed primarily to isolate primary power system equipment and provide a visual indication of isolation through a mechanical airgap. One of the most common types of load-break disconnect switch designs is the vertical-break switch type. The isolating mechanism of vertical-break disconnect switches consists of a hinged switch blade that physically swings upward and disconnects from a stationary jaw. Vertical-break switches are in the closed state when the switch blades are in the horizontal position and in the open state when the switch blades are in the vertical position. Many load-break switches in service today can only be operated manually by rotating a swing handle. The time it takes for the switch blade to go from fully closed to fully open can be in the range of 3 to 5 seconds.

Load-break vertical-break disconnect switches can be outfitted with a series of interrupting bottle units, containing either a vacuum or sulfur hexafluoride (SF<sub>6</sub>) gas as the interrupting dielectric medium [2]. These interrupting units allow the disconnect switch to have a greater capacity for breaking load current. Prior to the physical isolation of the disconnect switch through the mechanical swinging of the switch blade, the arcing current is diverted to the interrupting bottle units for the extinguishing of the arc. Fig. 2 shows a typical vertical-break disconnect switch outfitted with interrupter units that allow the disconnect switch to break load.



Fig. 2. Typical load-break disconnect switch.

According to one manufacturer, their 138 kV load-break disconnect switch includes five vacuum bottles in series for grading the voltage profile across the open contacts. Each bottle takes 2 cycles to operate, but they should all receive the open command at the same time during normal switching operations. One manufacturer indicated that time for maximum pole scatter could be 45 to 60 cycles on a well-maintained and properly adjusted switch. The typical pole-scatter duration could be in the range of 10 to 12 cycles. While these switches are designed for the interrupting requirements associated with load switching, loop switching, and line-charging switching, they are not designed for minimal pole-scatter durations.

Open pole conditions during line switching have been discussed in many technical papers and other literature. A detailed discussion on modeling in-line switching or open phase conductors, along with symmetrical component analysis, is presented in [3]. A few switching conditions were simulated in a dynamic simulator and are discussed in the next section. Two real-world cases, one for internal switching and one for external, are discussed in the later sections of this paper.

## II. SIMULATION CASE STUDY

### A. Single-Phase Open Condition—External Switching

In Fig. 3, the opening of the A-phase of Switch SW1 results in an unbalance in the currents seen by the relays located at Terminal L and Terminal R. From Fig. 4, it is evident that upon the opening of the A-phase of SW1, the A-phase line current (ILA) seen by the relay at Terminal L goes to zero and there is an immediate surge in the negative-sequence and zero-sequence currents ( $|I2\_IL|$  and  $|I0\_IL|$ ).

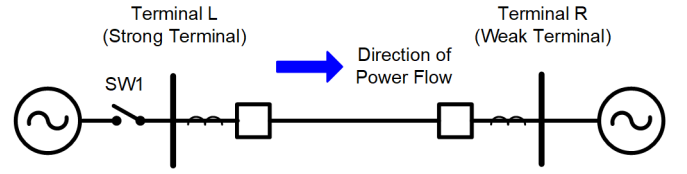


Fig. 3. Transmission line switching.

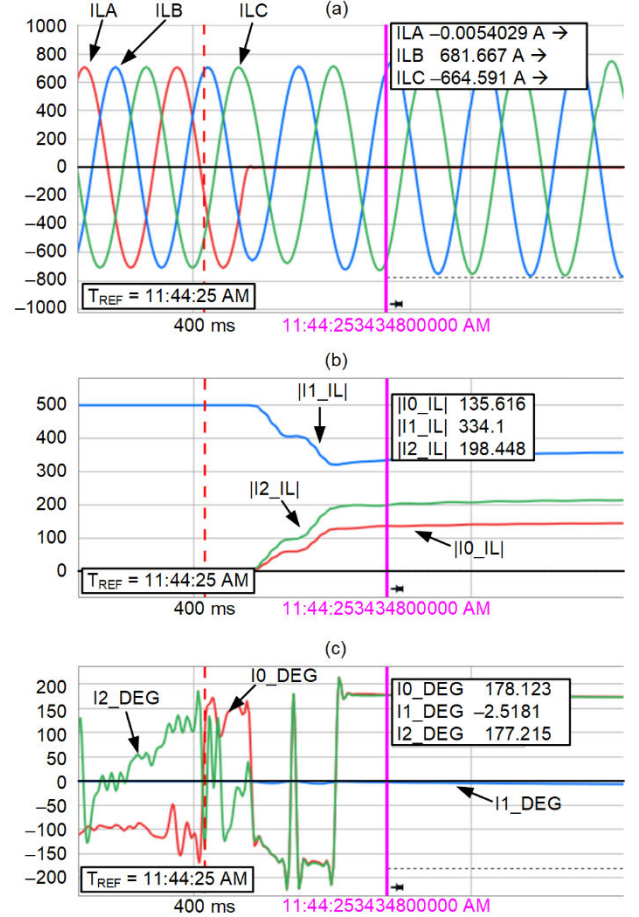


Fig. 4. Single-phase open condition: Terminal L (a) phase currents (A), (b) sequence current magnitudes (A), and (c) sequence current angles (degrees).

The symmetrical component connection diagram for a single-phase open condition is similar to a phase-to-phase-to-ground fault [3]. The through-load positive-sequence current ( $|I1\_IL|$ ) divides between the negative- and zero-sequence networks and by observing the magnitudes, it is clear that  $|I1\_IL| = -(I2\_IL + I0\_IL)$ . In the case of a radial system, the relays at both the ends of the line are subjected to the same sequence currents. The magnitude of the sequence current is dependent on the load-flow condition through the transmission line and strength of the sources. As the load flow increases, the magnitude of the sequence currents also increases [3]. It can be observed from the angles of the negative- and zero-sequence currents ( $I2\_DEG$  and  $I0\_DEG$ ) that the sequence currents flow in the opposite direction than that of the positive-sequence load current ( $I1\_DEG$ ). The negative-sequence and zero-sequence currents are in phase.

### B. Double-Phase Open Condition—External Switching

In Fig. 3, the opening of the A- and B-phase of SW1 results in unbalance in the currents seen by the relays situated at Terminal L and Terminal R. From Fig. 5, it is evident that upon the opening of the A- and B-phases of the switch, the A-phase and B-phase line currents ( $I_{LA}$  and  $I_{LB}$ ) seen by the relay at Terminal L go to zero and there is an immediate surge in the negative-sequence and zero-sequence currents. The symmetrical component connection diagram for a double-phase open condition is similar to a phase-to-ground fault [3]. The magnitudes of positive-, negative-, and zero-sequence currents ( $|I1\_IL|$ ,  $|I2\_IL|$ , and  $|I0\_IL|$ ) are equal. ( $|I1\_IL|$  may not be equal to  $|I2\_IL|$ , and  $|I0\_IL|$  in all cases, for example, if there are tapped loads on the line.) The phase and sequence currents seen by the relay at Terminal R are similar to the currents seen by the relay at Terminal L for this radial system.

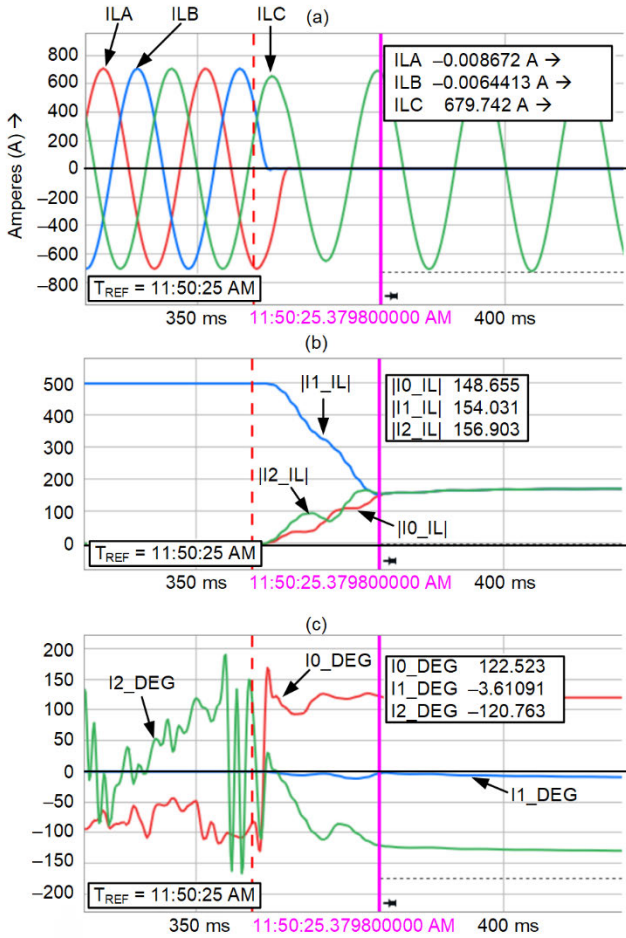


Fig. 5. Double-phase open condition: Terminal L (a) phase currents (A), (b) sequence current magnitudes (A), and (c) sequence current angles (degrees).

The phase difference between the negative-sequence and zero-sequence currents is around 240 degrees in this case.

### C. Scattered-Pole Opening/Closing Condition—Internal Switching

In the two-terminal line shown in Fig. 6, Terminal L represents the weak terminal and Terminal R represents the strong terminal with regards to power flow. Initially SW1 is closed, SW2 is open, and the tapped load L1 is fed from the source in Terminal L. Upon the closing of all the three poles of SW2, Terminal L1 is fed from the strong source (Terminal R) and the power system enters into a new steady-state load-flow state. This change should typically not result in a significant unbalance.

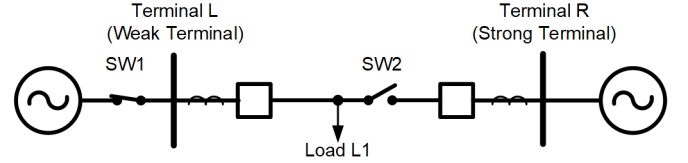


Fig. 6. Scattered pole closing.

A scattered closing of the poles of SW2, however, can cause an unbalance in the load flow during this interim period between the closing of the poles, as shown in Fig. 7. The B-phase of SW2 closed first, followed by the delayed closing of the A- and C-phases. With the closing of the B-phase of SW2, a sharp increase can be witnessed in the current ( $I_{RB}$ ) from Terminal R and a corresponding decrease can be witnessed in the current from Terminal L ( $I_{LB}$ ), clearly indicating a change in the steady-state load-flow condition. Similar changes can be observed in the A-phase ( $I_{LA}$ ,  $I_{RA}$ ) and C-phase ( $I_{LC}$ ,  $I_{RC}$ ) currents from both the terminals, respectively. This results in an unbalance in the load flow and a significant increase can be observed in the zero-sequence currents ( $|I0\_IL|$  and  $|I0\_IR|$ ) and negative-sequence currents ( $|I2\_IL|$  and  $|I2\_IR|$ ) at both the terminals, as shown in Fig. 8.

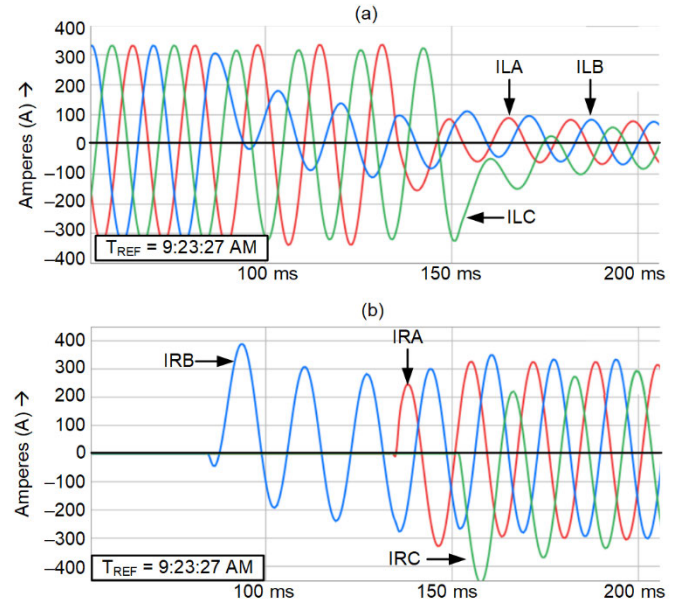


Fig. 7. Scattered pole closing: Terminals (a) L and (b) R phase currents (A).

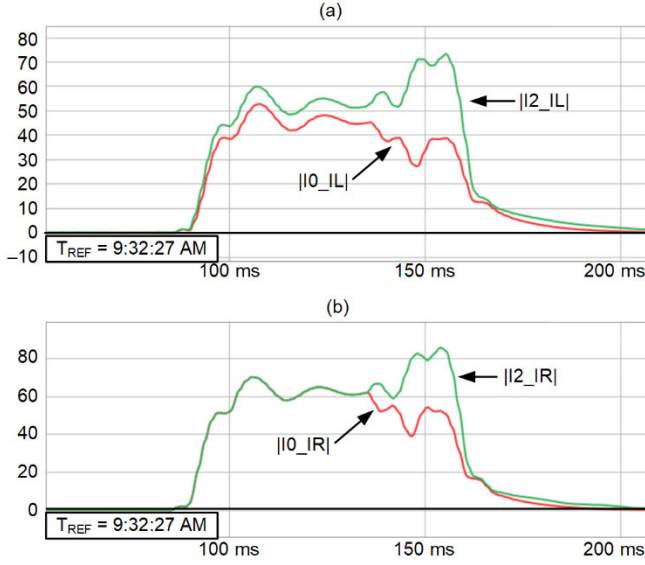


Fig. 8. Scattered pole closing: Terminals (a) L and (b) R sequence current magnitudes (A).

### III. INTERNAL LINE SWITCHING EVENT—REAL-WORLD CASE STUDY 1

Because of maintenance activities, the utility operations group needed to isolate a section of a three-terminal transmission line while keeping the rest of the transmission line and its associated tapped distribution loads online. To minimize utility outages, the operations group opened transmission line Disconnect Switch DS161. Upon completion of maintenance activities, DS161 was closed to restore the normal power system configuration. Fig. 9 shows the one-line diagram of the three-terminal line.

Table I shows the approximate steady-state load-flow states with DS161 opened and DS161 closed.

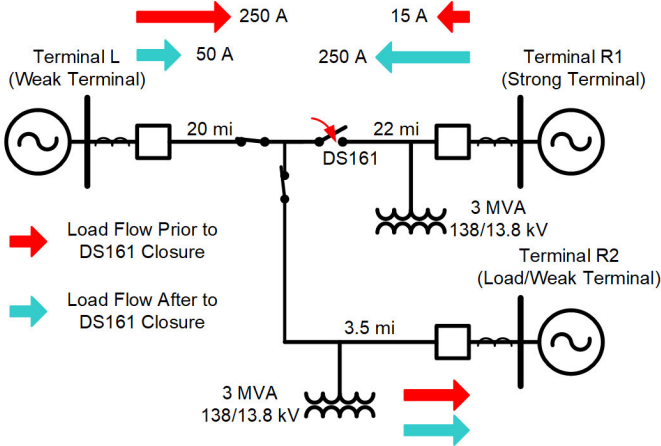


Fig. 9. Three-terminal transmission line one-line diagram.

TABLE I  
STEADY-STATE LOAD-FLOW DATA

| Load-Flow State | DS161 Status | Weak Terminal (L)             | Strong Terminal (R1)          |
|-----------------|--------------|-------------------------------|-------------------------------|
| State 1         | Open         | 250 A<br>PF = 0.95<br>Leading | 15 A<br>PF = 0.95<br>Lagging  |
| State 2         | Closed       | 50 A<br>PF = 0.95<br>Leading  | 250 A<br>PF = 0.95<br>Leading |

The transition from one balanced three-phase steady-state load-flow state to another state should not typically cause the pilot protection scheme to operate. However, because the transition from State 1 to State 2 resulted in a severely unbalanced load flow for more than 4 cycles, the pilot protection scheme misoperated through the assertion of the directional ground overcurrent tripping (67G2) elements.

The source of the unbalanced load flow was the pole scatter associated with the closing of DS161. The B-phase of the disconnect switch made contact and conducted first, resulting in a sharp increase in B-phase current from the strong terminal (Terminal R1) and a sharp decrease in B-phase current from the weak terminal (Terminal L). The sharp change in B-phase current occurred because the load flow of the transmission system shifted when the strong terminal became the major source of power for Terminal R2. After 3 cycles, the A-phase began to conduct, followed by the C-phase after an additional cycle. See Fig. 10 and Fig. 11 for event report snapshots that show the phase currents at two of the three terminals during the transmission line switching. The event report data for Terminal R2 are not available because Terminal R2 did not trip or produce an event report during this event.

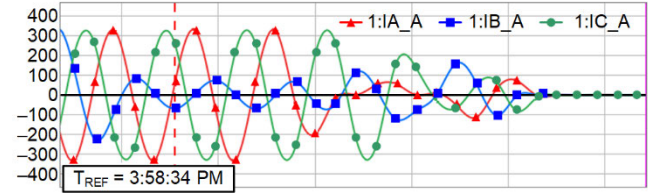


Fig. 10. Phase currents (A) for weak terminal (L).

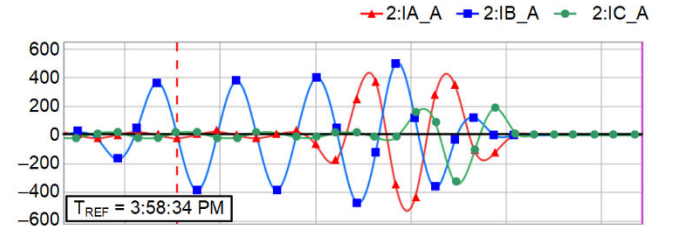


Fig. 11. Phase currents (A) for strong terminal (R1).

The closing of DS161 caused the current signature at the weak terminal to see 3 cycles of what appears to be a one-pole-open (1PO) condition, followed by 1 cycle of a what appears to be a two-pole-open (2PO) condition. For the strong terminal, the current signature was the converse; the 2PO condition was observed for 3 cycles, followed by the 1PO condition for 1 cycle.

For this three-terminal transmission line, the pilot protection included a directional comparison blocking (DCB) scheme over a power line carrier that employed 67G elements, ground mho (21G) elements, and phase mho (21P) elements. The ground directional elements were set with the negative-sequence voltage-polarized directional (32Q) element as the polarization choice with the highest priority. The directional element was set the traditional way based on the equivalent transmission line impedance where Z2F was set to half of the equivalent transmission line impedance and Z2R was set 0.1  $\Omega$  higher than the Z2F setting. The DCB scheme included a carrier coordination timer set at 1 cycle to allow time for the block signal to arrive from the remote end.

#### A. 67G Element Response to Event

The 67G elements used in the pilot scheme misoperated during this unbalanced load flow by tripping Terminal L and Terminal R1. Fortunately, Terminal R2 was unaffected and remained closed, keeping the tapped loads on the three-terminal line energized. Considering that the summation of the zero-sequence current for the three terminals should equal zero for load unbalance and series faults for this system configuration, the zero-sequence current at Terminal R2 can be determined by taking the negative of the sum of the zero-sequence currents at Terminal L and Terminal R1, as shown by (1).

$$I_{L,0} + I_{R1,0} + I_{R2,0} = 0 \quad (1)$$

Fig. 12 shows the zero-sequence current (3I0) at Terminals L, R1, and calculated R2 based on (1). The top graph shows the waveforms, while the bottom graph shows the magnitudes. According to Fig. 12, the calculated residual current at Terminal R2 was less than 100 A primary throughout the event, which was less than the 67G2 pickup of 180 A primary. If Terminal R2 had seen a higher residual ground current, it also would have most likely operated.

The 67G2 element was set higher than 10 percent of the maximum winter emergency load current of 816 A primary to account for natural unbalance according to the protection philosophy of the utility. With the 67G2 element set with a pickup of 180 A primary, ground current (3I0) as high as 250 A primary during the event was enough to assert the 67G2 element at Terminal L and R1. Because the three-phase pole closure of DS161 took more than 4 cycles, the DCB scheme operated through its 67G2 elements as soon as the carrier coordination time delay elapsed.

Fig. 13 and Fig. 14 show the dynamic negative-sequence directional thresholds plotted with the measured negative-sequence impedance for the weak and strong terminal, respectively.

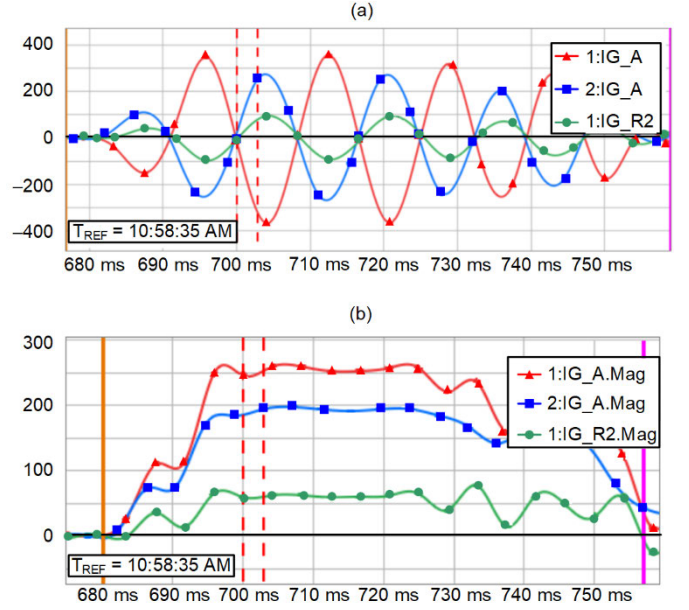


Fig. 12. Residual ground current (A) for Terminal L (square), Terminal R1 (triangle), and calculated Terminal R2 (circle).

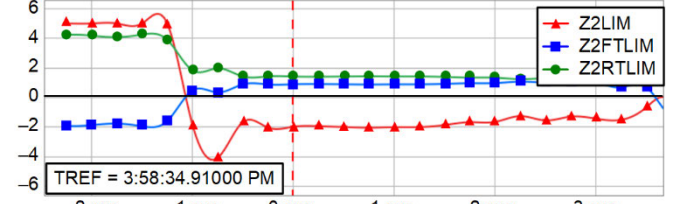


Fig. 13. Measured Z2 (Z2LIM), Z2F forward threshold (Z2FTLIM), and Z2R reverse threshold (Z2RTLIM) for weak terminal (L).

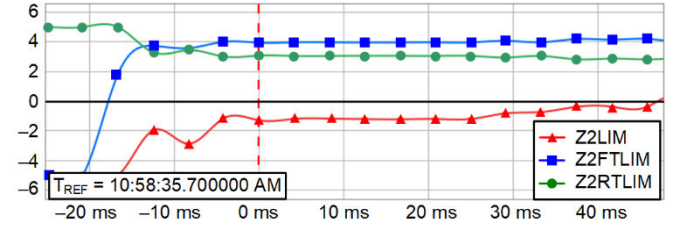


Fig. 14. Measured Z2 (Z2LIM), Z2F forward threshold (Z2FTLIM), and Z2R reverse threshold (Z2RTLIM) for strong terminal (R1).

As for the response of the 32Q directional elements, the event report data agree with the classical symmetrical fault analysis for 1PO and 2PO conditions where the directional elements at Terminals L and R1 asserted in the forward direction [3] [4]. The measured Z2 was considerable at less than  $-1.0 \Omega$  at Terminals L and R1. Modifying the forward (Z2F) and reverse (Z2R) thresholds to Z2F =  $-0.3 \Omega$  secondary and Z2R =  $0.3 \Omega$  secondary would not have helped prevent the 32Q directional element from asserting in the forward direction for Terminals L and R1 for this event. Fig. 15 and Fig. 16 provide additional event report data for the weak and strong terminals, respectively.

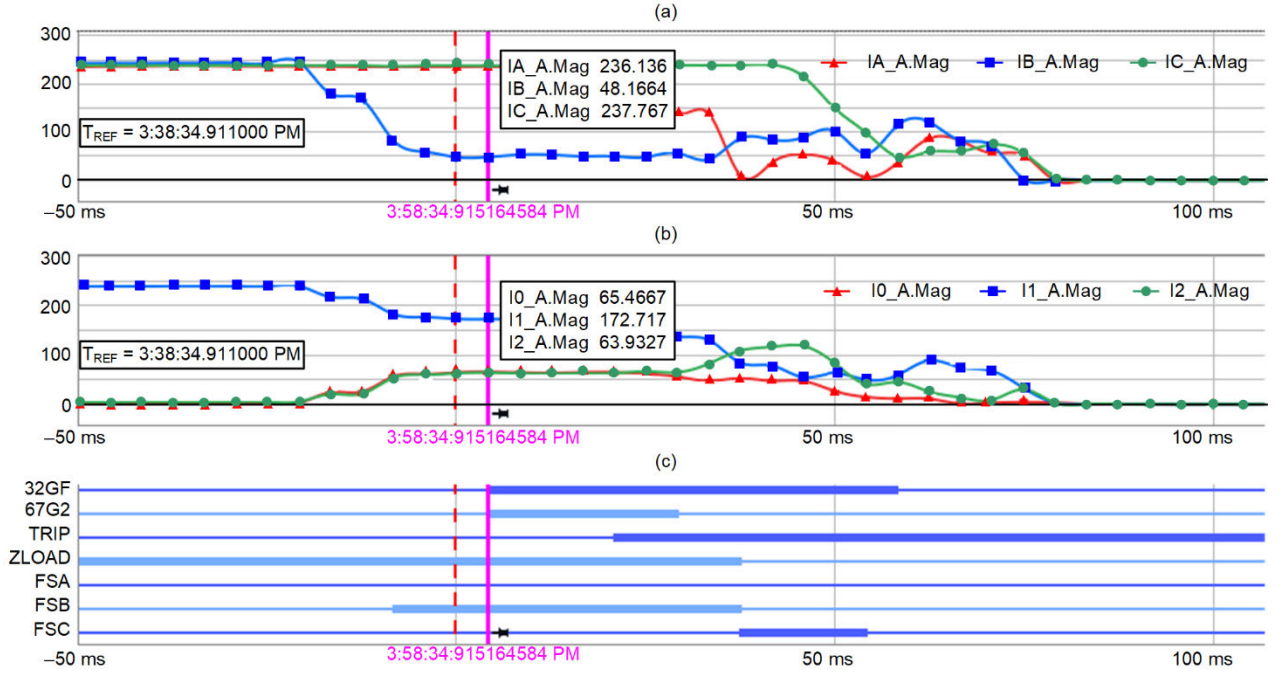


Fig. 15. Event report from weak terminal (L) for (a) phase currents magnitude (A), (b) sequence currents magnitude (A), and (c) relay digital signals.

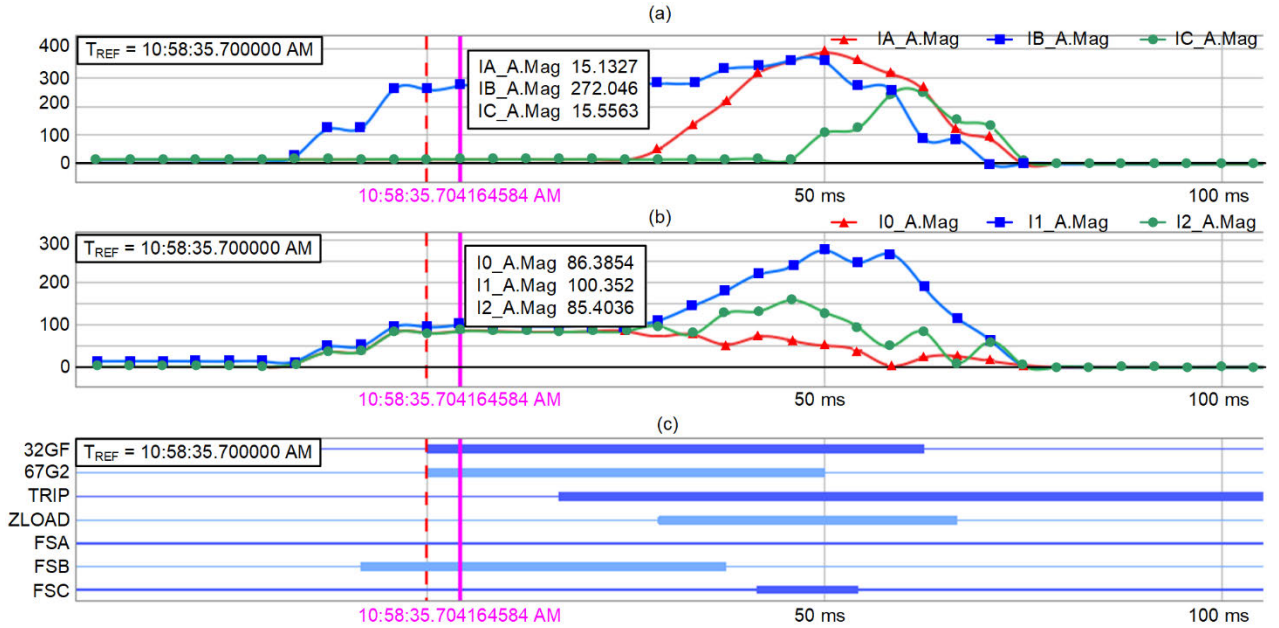


Fig. 16. Event report from strong terminal (R1) for (a) phase currents magnitude (A), (b) sequence currents magnitude (A), and (c) relay digital signals.

For this particular event, the 67G2 element operated but the 21G element did not. The 67G2 element is much more susceptible to misoperating during transmission line switching compared to any other ground element due to its sensitivity [3].

#### B. 21G Element Response to Event

Although the distance elements did not operate for this event, the response of the ground-distance elements provides insight into how distance elements respond to an unbalanced load flow. Only the mho distance elements were used in the settings and have been studied in this paper. The quadrilateral ground-distance elements have not been analyzed as a part of this paper.

During the first 3 cycles of the event where only the B-phase of DS161 was closed, the angle difference between IA2 and IA0 at Terminal L and Terminal R1 was  $-120$  degrees ( $\theta_{IA2} - \theta_{IA0} = -120$  degrees), thus activating the B-phase mho ground-distance element (MBG) and the C-A mho phase-distance element (MCA) according to the fault identification selection (FIDS) logic [5]. Once the A-phase of DS161 closed 3 cycles later, the angle difference between IA2 and IA0 shifted to  $120$  degrees ( $\theta_{IA2} - \theta_{IA0} = 120$  degrees), thus deactivating the MBG and MCA elements and activating the C-phase mho ground-distance element (MCG) and the A-B mho phase-distance element (MAB) [5].

For each impedance loop (MAG, MBG, MCG, MAB, MBC, and MCA), the mho element operates when the respective apparent impedance falls within the mho circle characteristic. For any set of voltages and currents, the lowest mho element reach required for the operation of each impedance loop can be calculated using the equations in Table II. Only MBG, MCA, MCG, and MAB impedance loops are involved with this event.

Table III shows the results of the equations [6] in Table II for the strong terminal. The values shown for each impedance loop are the averages over the corresponding time intervals. The bolded numbers indicate the active mho elements based on the FIDS logic.

Based on the reach calculations during each point of the event report, it is apparent that between the two active

impedance loops, MBG and MCA, MBG requires the lowest reach for operation when DS161 is in the 2PO condition. When DS161 fully transitions to the 1PO condition, the lowest mho element reach required for operation, between the active impedance loops MCG and MAB, was for the MAB impedance loop. Fig. 17 graphically shows how the minimum reach calculations for each impedance loop are affected by the event data. For the DS161 2PO condition, the calculated results for MBG and MCA are stable. When DS161 transitions from the 2PO condition to the 1PO condition, the A-B impedance loop minimum reach result appears volatile before stabilizing after 5.50 cycles into the event (Point 22). The magnitude for the C-G impedance loop reach is large for Point 23 (5.75 cycles), which is expected for a 1PO condition involving C-phase.

TABLE II  
IMPEDANCE LOOP EQUATIONS†

| Impedance Loop | Apparent Impedance                                | Impedance Loop Minimum Reach Equation                                                                                                                                                                  |
|----------------|---------------------------------------------------|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| AG             | $Z_{AG,APP} = \frac{V_{AG}}{I_A + k0 \cdot 3I_0}$ | $R_{AG} = \frac{\text{Re}(V_{AG} \cdot V_{A1mem}^*)}{\text{Re}[(1\angle\theta_{ZIL}) \cdot (I_A + k0 \cdot 3I_0) \cdot V_{A1mem}^*]}$                                                                  |
| BG             | $Z_{BG,APP} = \frac{V_{BG}}{I_B + k0 \cdot 3I_0}$ | $R_{BG} = \frac{\text{Re}[V_{BG} \cdot (\alpha^2 \cdot V_{A1mem})^*]}{\text{Re}[(1\angle\theta_{ZIL}) \cdot (I_B + k0 \cdot 3I_0) \cdot (\alpha^2 \cdot V_{A1mem})^*]}$                                |
| CG             | $Z_{CG,APP} = \frac{V_{CG}}{I_C + k0 \cdot 3I_0}$ | $R_{CG} = \text{Re} \frac{\text{Re}[V_{CG} \cdot (\alpha \cdot V_{A1mem})^*]}{\text{Re}[(1\angle\theta_{ZIL}) \cdot (I_C + k0 \cdot 3I_0) \cdot (\alpha \cdot V_{A1mem})^*]}$                          |
| AB             | $Z_{AB,APP} = \frac{V_{AG} - V_{BG}}{I_A - I_B}$  | $R_{AB} = \frac{\text{Re}\{ (V_{AG} - V_{BG}) \cdot [(1 - \alpha^2) \cdot V_{A1mem}]^* \}}{\text{Re}\{ (1\angle\theta_{ZIL}) \cdot (I_A - I_B) \cdot [(1 - \alpha^2) \cdot V_{A1mem}]^* \}}$           |
| BC             | $Z_{BC,APP} = \frac{V_{BG} - V_{CG}}{I_B - I_C}$  | $R_{BC} = \frac{\text{Re}\{ (V_{BG} - V_{CG}) \cdot [(\alpha^2 - \alpha) \cdot V_{A1mem}]^* \}}{\text{Re}\{ (1\angle\theta_{ZIL}) \cdot (I_B - I_C) \cdot [(\alpha^2 - \alpha) \cdot V_{A1mem}]^* \}}$ |
| CA             | $Z_{CA,APP} = \frac{V_{CG} - V_{AG}}{I_C - I_A}$  | $R_{CA} = \frac{\text{Re}\{ (V_{CG} - V_{AG}) \cdot [(\alpha - 1) \cdot V_{A1mem}]^* \}}{\text{Re}\{ (1\angle\theta_{ZIL}) \cdot (I_C - I_A) \cdot [(\alpha - 1) \cdot V_{A1mem}]^* \}}$               |

† where:

$V_{A1mem}$  is the positive-sequence memory voltage for  $V_{AG}$ .

$\alpha$  is defined as  $1\angle 120^\circ$ .

$(1\angle\theta_{ZIL})$  is the unity vector with line impedance angle.

$k0$  is the zero-sequence compensation factor.

TABLE III  
IMPEDANCE LOOP REACH ( $\Omega$  SECONDARY) VARIATIONS AT STRONG TERMINAL

| Points | Cycles    | 1PO/2PO | $R_{AG}$ | $R_{BG}$   | $R_{CG}$      | $R_{AB}$    | $R_{BC}$ | $R_{CA}$      |
|--------|-----------|---------|----------|------------|---------------|-------------|----------|---------------|
| 12–18  | 3.00–4.50 | 2PO     | 160      | <b>480</b> | –170          | –650        | 280      | <b>3,450</b>  |
| 19–21  | 4.75–5.25 | 1PO/2PO | 250      | <b>620</b> | <b>–300</b>   | <b>–880</b> | 230      | <b>–1,820</b> |
| 22–24  | 5.50–6.00 | 1PO     | 200      | 900        | <b>–7,200</b> | <b>330</b>  | 190      | –340          |

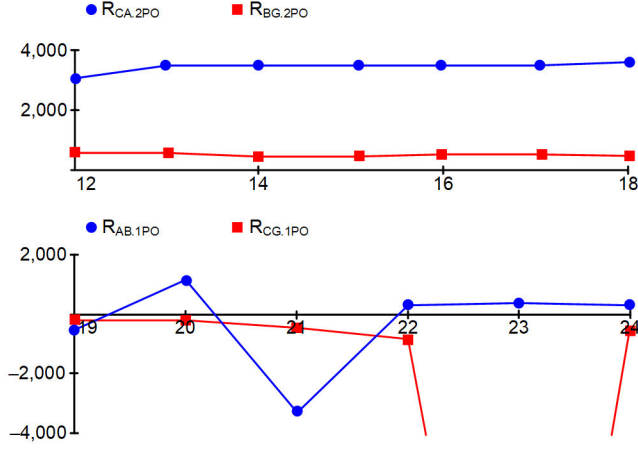


Fig. 17. Impedance loop reach ( $\Omega$  secondary) variations graph at strong Terminal (R1).

Table IV shows the results of the equations in Table II for the weak terminal. Similar to Table III, the values shown for each impedance loop are the averages over the corresponding time intervals, and the bolded numbers indicate the active mho elements based on the FIDS logic. When DS161 was in the 2PO condition, the minimum reaches for both active impedance loops, MBG and MCA, are both negative and large. When DS161 was in the 1PO condition, the lowest mho element reach required for operation was for the MAB impedance loop. As shown in Fig. 18, there is a large fluctuation in the reach calculation for the MCG impedance loop during the DS161 1PO time interval (8.25–8.75 cycles). Hence, the average value of 240, as shown in Table IV, is not an accurate representation of the lowest reach and can be ignored. (For reference, the rms value for reach calculation during this time period is 3,900.)

Fig. 18 graphically shows the minimum reach calculations for the weak terminal for each event data point. For the DS161 2PO condition, the MCA impedance loop results in the smallest reach, which is what was expected, considering that the weak terminal saw a sudden drop in the B-phase current. Similar to the strong terminal, the MAB impedance loop appears to be the impedance loop with the lowest reach during the DS161 1PO condition, stabilizing after 8 cycles into the event (Point 32).

Although mho elements use positive-sequence memory polarization, mho elements can be characterized as responding very similarly to self-polarized mho elements when the line voltages remain relatively unchanged, as is the case for many

transmission line switching events, including this example event. Hence, for simplification, ignoring the complex expansion of the mho circle due to positive-sequence memory polarization is a reasonable assumption. Fig. 19 illustrates the MBG ground-distance element response to this event at the strong terminal. Prior to the closing of DS161, the strong terminal saw a balanced load flow, and all impedance loops saw an apparent impedance of  $2,000 \Omega$ . Once the B-phase of DS161 started to conduct, the apparent impedance for the BG impedance loop decreased drastically to  $61 \Omega$  for about 3 cycles, though still far outside the mho circle characteristic of the Z2MG relay reach setting. Next, when the A-phase of DS161 closed, the apparent impedance increased slightly to  $65 \Omega$ . Just as the C-phase of DS161 was starting to close, the breaker at the strong terminal was already in the process of tripping with its 52A status deasserting 0.25 cycles later. Hence, the event report only has two data points of transient data for the apparent impedance when all three phases of DS161 appeared closed. The movement of the apparent impedance during the event highlights how the apparent impedance during unbalanced load conditions can be driven closer to the origin and more likely to fall within the ground-distance element characteristic.

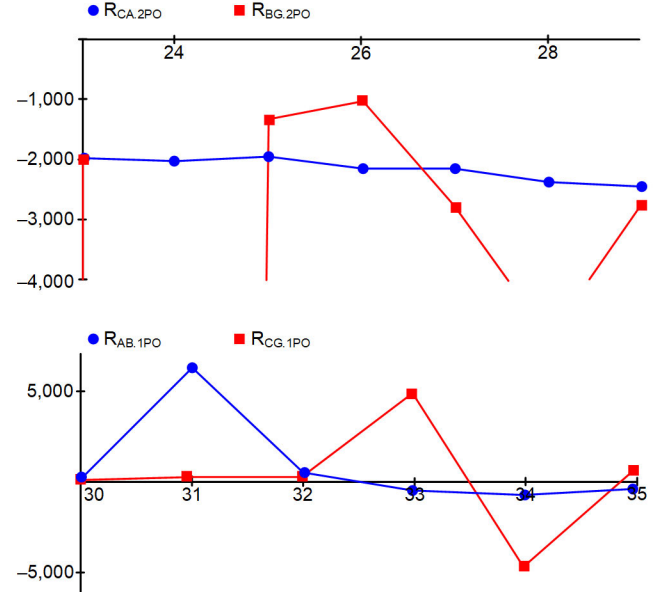


Fig. 18. Impedance loop reach ( $\Omega$  secondary) variations graph at weak Terminal (L).

TABLE IV  
IMPEDANCE LOOP REACH ( $\Omega$  SECONDARY) VARIATIONS AT WEAK TERMINAL

| Points | Cycles    | 1PO/2PO | R <sub>AG</sub> | R <sub>BG</sub> | R <sub>CG</sub> | R <sub>AB</sub> | R <sub>BC</sub> | R <sub>CA</sub> |
|--------|-----------|---------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|
| 23–29  | 5.75–7.25 | 2PO     | –110            | <b>–27,780</b>  | 140             | 400             | –240            | <b>–2,150</b>   |
| 30–32  | 7.50–8.00 | 1PO/2PO | –150            | <b>3,090</b>    | <b>210</b>      | <b>2,400</b>    | –210            | <b>–9,150</b>   |
| 33–35  | 8.25–8.75 | 1PO     | –230            | 4,500           | <b>240</b>      | <b>–510</b>     | –150            | 190             |

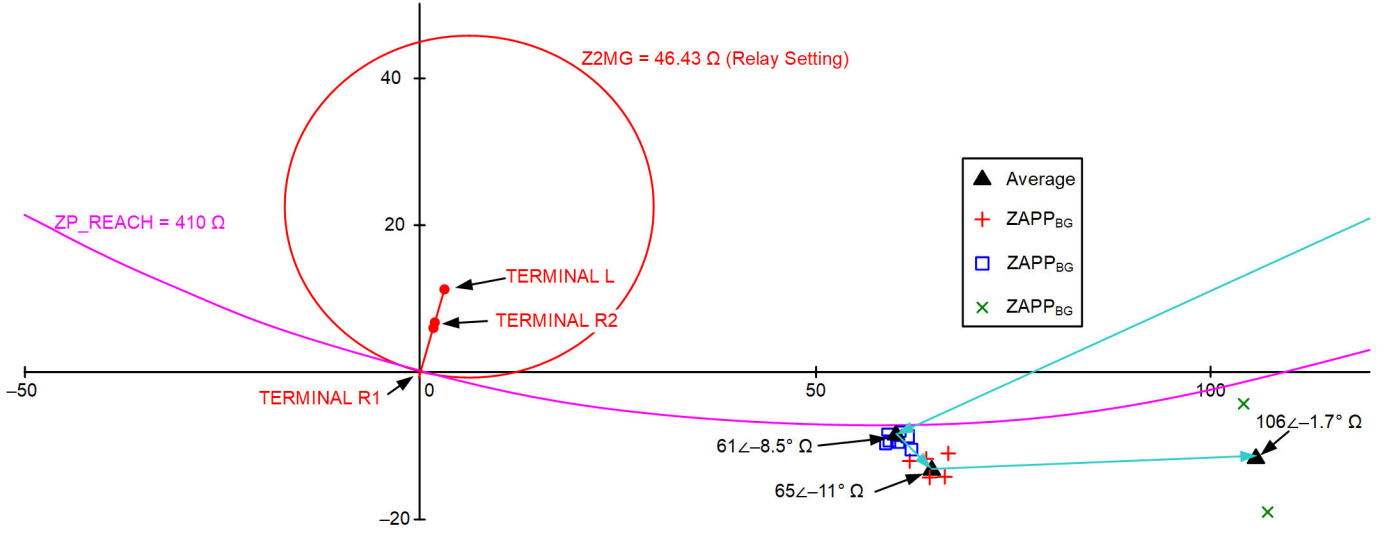


Fig. 19. MBG element response at strong terminal (Terminal R1).

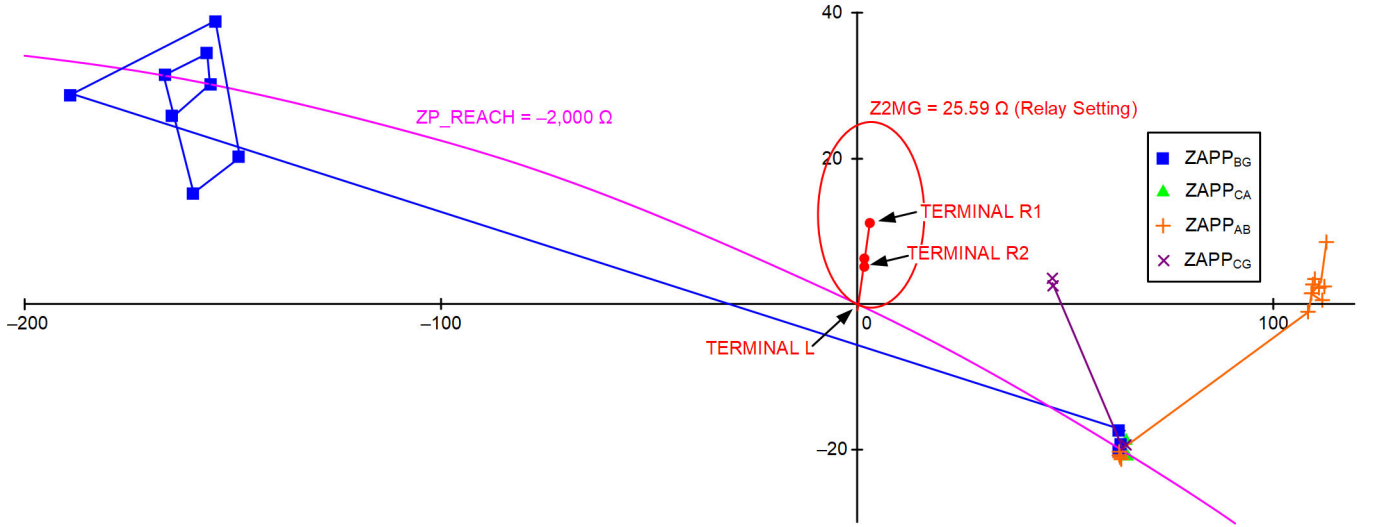


Fig. 20. MBG element response at weak terminal (Terminal L).

Based on Fig. 19, even the maximum setting of  $64 \Omega$  for the ground mho element would not have resulted in a trip, largely because of the leading power factor. The event shows that the mho ground element at the strong terminal must be set at  $410 \Omega$  to produce a trip. This huge mho element reach highlights the sensitivity of the 67G element. While the 21G element is unlikely to trip under an unbalanced load flow with a leading power factor, the 67G2 element can operate regardless of the power factor of the load flow.

Fig. 20 shows how the mho elements at the weak terminal respond to the event for the first 3 cycles. Because the pre-fault data consist of a balanced load flow with a leading power factor, all apparent impedances begin with an impedance of  $(66\angle-17^\circ) \Omega$ . Because the strong terminal had a lower potential transformer (PT) ratio at 700:1 versus 1200:1 at the weak terminal, this impedance is equivalent to  $(113\angle-17^\circ) \Omega$ , if making comparisons with the strong terminal.

From the event report data, the effects of load unbalance are much more pronounced for terminals that experience a 2PO condition, such as the mho elements of the strong terminal in

this event. The IPO condition experienced by the weak terminal kept the MCA apparent impedance fixed in its previous position and moved the MBG apparent impedance even farther out.

#### IV. EXTERNAL LINE SWITCHING EVENT—REAL-WORLD CASE STUDY 2

Fig. 21 shows a three-terminal line application with line switching performed by the utility behind Terminal L on an adjacent line. In June of 2013, four events were recorded within a 15-minute interval. Two of the four events resulted in an undesired pilot protection trip in the forward direction. The other two events resulted in no trip when the unbalance was detected in the reverse direction. Event reports were only available from the relay at Terminal L for these events. The primary protection, designated as System A by the utility, for this 138 kV three-terminal line includes a DCB scheme application. The secondary protection, or System B, includes step distance and other time-delayed backup elements. The three ends of the line had a different type of relay applied in the pilot scheme.

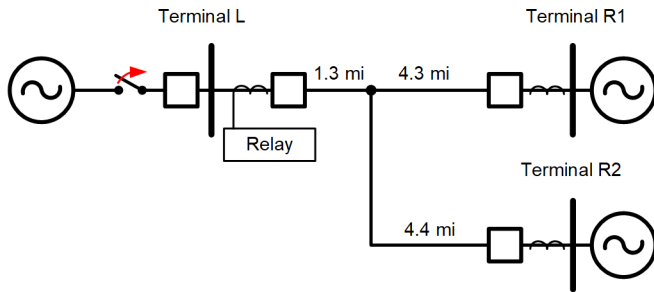


Fig. 21. Simplified one-line diagram for the external switching event.

Similar to Case Study 1, for this three-terminal transmission line, the pilot protection at Terminal L in the DCB scheme employed 67G elements, 21G elements, and 21P elements. The ground directional elements were set with the 32Q element as the polarization choice with the highest priority (ORDER = QV). The negative-sequence directional element was set the traditional way based on the equivalent transmission line impedance, where  $Z2F = 0.22 \Omega$  was set to half of the equivalent transmission line impedance and  $Z2R$  was set  $0.1 \Omega$  higher at  $Z2R = 0.32 \Omega$ . The DCB scheme included a carrier coordination timer set at 1 cycle to allow time for the block signal to arrive from the remote end.

Fig. 22 shows the event report captured for one external switching event where the relay identified the switching unbalance as reverse. This event did not result in a trip, as expected. The FIDS logic in the relay identified the unbalance on the C-phase with the pickup of FSC word bit [5]. For all four events, the C-phase unbalance is the highest, indicating a potential misalignment with the C-phase of the line switch. The magnitude of increase in current on the C-phase during all events is in the order of two to three times the pre-event load current. The relay identified the event as a CG fault, in line with the expected phase angle relationship, where  $I2$  leads  $I0$  by 120 degrees, as shown in Fig. 23 [5]. The switching unbalance lasted for about 5.5 cycles before settling down to approximately the same pre-event steady-state load-flow condition.

IN206 in the relay receives the carrier start or block signal from the two remote ends. It is interesting to note that one or both remote ends identified the event as reverse and asserted the block signal. The dynamic negative-sequence impedance thresholds are plotted with the calculated negative-sequence impedance for Terminal L and the resultant  $Z2$  value falls higher than the  $Z2R$  threshold, indicating a reverse direction [7] [8].

Fig. 24 shows the event report captured for the external switching event where the relay identified the switching unbalance in the forward direction. The high-set ground overcurrent element (67G2) picked up and stayed asserted for the required carrier coordination time interval, resulting in an undesired trip.

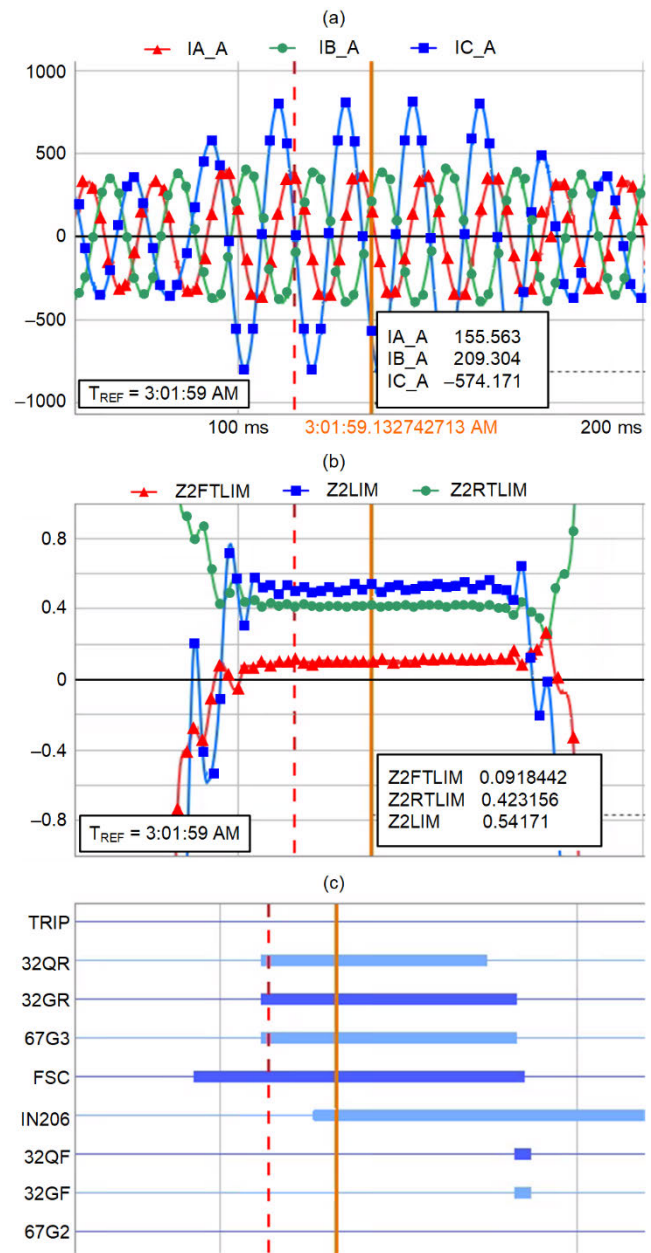


Fig. 22. Reverse direction decision for external switching event at Terminal (L) for (a) phase currents (A), (b) negative-sequence impedance magnitude vs. thresholds ( $\Omega$ ), and (c) relay digital signals.

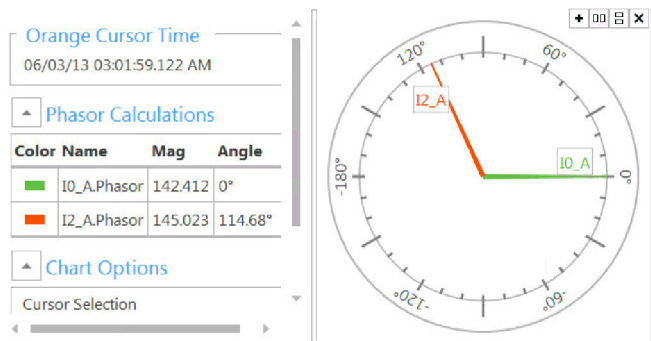


Fig. 23. External switching event for  $I2$  and  $I0$  phasors.

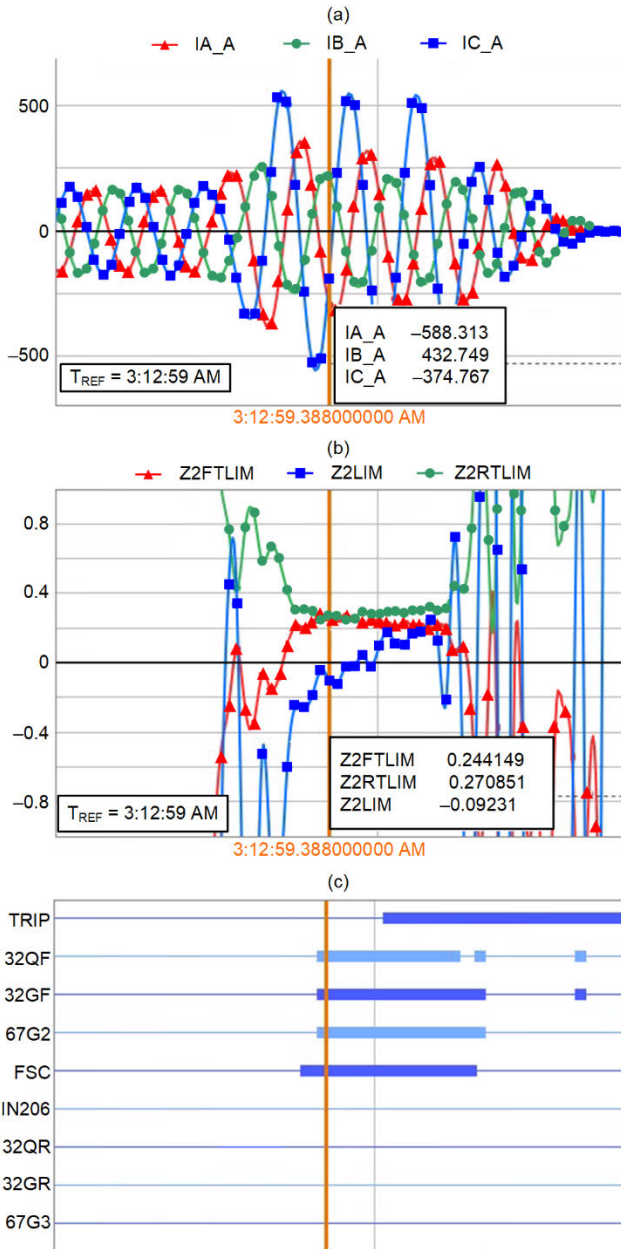


Fig. 24. Forward direction decision for external switching event at Terminal (L) for (a) phase currents (A), (b) negative-sequence impedance magnitude vs. thresholds (Ω), and (c) relay digital signals.

Similar to Case Study 1, according to the protection philosophy of the utility, the pickup for 67G2 was set higher than 10 percent of the maximum winter emergency rating of the line to prevent 67G2 from tripping for a natural unbalance in the system. This element is typically set sensitively enough to cover for ground faults in the zone of protection with sufficient multiples of margin under required contingency conditions and to provide for high-resistance fault coverage. While the sensitivity is desired for an actual fault condition, line switching events external and internal to the line challenge the security of these settings. In this case, the zero-sequence current during the unbalance exceeded the pickup threshold.

Note that for this case, the reverse directional elements did not pick up and a block was not received from the remote end (via IN206). The remote end relays either saw this event correctly in their forward direction or did not see it at all. The dynamic negative-sequence directional thresholds are plotted with the calculated negative-sequence impedance for Terminal L and the resultant Z2 value falls less than the Z2F threshold indicating a forward direction [7] [8].

The solution employed for this case was to revise the Z2F and Z2R thresholds to  $-0.3$  and  $0.3$  Ω secondary, respectively, as discussed in [7]. In addition, the utility planned to service and calibrate the switch to correct any out-of-adjustment issues in the C-phase that was observed through the event. Both events where a trip occurred show very low Z2 (as a result of low V2) measured during the unbalance. After adjusting the thresholds, the same events were run through the relays to confirm security during these conditions. Though only adjusting the thresholds worked for this case, one may need to use additional measures for certain line switching conditions. The following section discusses the various available solution options that many utilities use to address this challenge.

## V. PILOT PROTECTION IMPROVEMENTS

Pilot protection schemes are widely implemented because of their ability to provide higher sensitivity and security to line protection. The fault resistance coverage of pilot schemes is increased through the addition of sensitive 67G elements. Based on the event reports from both real-world case studies, previously discussed in this paper, the security of sensitive elements in pilot protection schemes can be challenged for both external and internal transmission switching events. The events presented use DCB schemes. A permissive overreaching transfer trip (POTT) scheme with echo logic would have likely faced similar challenges.

Through decades of operational experience, utilities have mitigated the security concerns of pilot schemes due to transmission line switching through several methods. Some of the practices employed by utilities today include the following:

- Desensitizing the forward directional element threshold.
- Supervising the sensitive 67G elements with the 21G elements.
- Using only ground-distance elements in the pilot scheme.
- Decreasing the sensitivity of the pilot protection elements.
- Using two levels of 67G elements in a pilot scheme.
- Disabling the pilot scheme when the present transmission line loading poses a risk.

### A. Desensitizing the Forward Directional Element Threshold

For external transmission line switching, the 32Q directional element can assert in the forward direction for small values of Z2. For Case Study 2, the observed Z2 was small (within the

range of  $[-0.1, 0.1]$  when the 67G2 element asserted in the forward direction. With small values for Z2, setting the Z2F threshold based on half of the line impedance could cause Z2 to fall within the forward region of the 32Q directional element. Adjusting the Z2F and Z2R thresholds to  $-0.3$  and  $0.3 \Omega$  secondary, respectively, according to the recommendations in [7] [9] [10], allows the 32Q element to stay secure when Z2 is small, which is known to occur when the line voltages remain balanced while the load current becomes unbalanced. Following these recommendations would have prevented the pilot scheme misoperations for the external switching event shown in Case Study 2.

For internal switching events, classical symmetrical component fault analysis shows that all line terminals should observe negative values for Z2 and see the event in the forward direction. Hence, only modifying the Z2F and Z2R thresholds may not help prevent operation of the 67G elements for all internal switching cases, similar to Case Study 1. Additional measures, such as the ones discussed in the following sections, must be considered.

#### B. Supervising the Sensitive 67G Elements With the 21G Elements

Supervising the 67G2 element with a less-sensitive 21G element reduces the sensitivity of the pilot scheme. This is similar to Section V.C where the 67G element is eliminated from the pilot scheme.

#### C. Using Only Ground-Distance Elements in the Pilot Scheme

In both case studies, ground-distance elements did not pick up. In many typical pilot scheme applications in which both 21G and 67G elements are used, the distance element reach settings are inherently set less sensitive than the 67G elements. Completely eliminating 67G elements from the pilot scheme helps enhance the security but compromises on sensitivity.

#### D. Decreasing the Sensitivity of the Pilot Protection Elements

During a pole-open condition, the residual current can increase to the magnitude of the full load current. When internal transmission line switching is expected, the pilot scheme 67G elements should be set much higher than the normal system unbalance of the transmission line. For simplicity, set the 67G element pickup based on the maximum load current.

Based on the protection philosophy of utilities, (2) can be considered with the margin  $K_M$  set, for example, between 1.1 to 1.3.

$$I_{67G} = K_M \cdot I_{MAXLOAD} \quad (2)$$

Because following this recommendation significantly decreases the fault resistance coverage of the high-speed pilot protection, adding a more-sensitive 67G pilot scheme element with a time delay may be needed to meet the fault resistance coverage requirements.

#### E. Using Two Levels of 67G Elements in a Pilot Scheme

Using two levels of 67G elements is another option. Set the first element higher than the maximum load, with a margin (as discussed in Section V.D), to cover all fault cases where fault current is more than the load.

Set the second element for the desired fault resistance coverage sensitivity with a time delay to ride through the maximum pole disagreement time of the line switch plus a safety margin. This is also discussed in [3], where a small safety margin of 2 cycles is recommended. As discussed in Section I, one manufacturer indicated that the time for the maximum pole scatter could be 45 to 60 cycles on a well-maintained and properly adjusted switch. If the time delay is set too high, the speed of these sensitive pilot scheme elements may be slower than the backup protection provided by the equally sensitive directional ground time-overcurrent elements and thus provide no benefit.

#### F. Disabling the Pilot Scheme When the Present Transmission Line Loading Poses a Risk to Transmission Switching

Prior to executing transmission switching orders, a decision is made on whether to disable the pilot scheme based on the present transmission line loading. If the present transmission line loading exceeds a certain threshold during the required transmission switching, the utility may choose to disable the pilot scheme to avoid inadvertent pilot scheme tripping. Typically, the engineering group provides the operations group with a formula to use when making the decision to disable the pilot protection scheme. As seen in Case Studies 1 and 2, because the risk is for both internal and external switching, one may need to disable pilot protection at both the local and remote ends of all lines close to the switching activity. For a fault during this time period, speed and sensitivity may be significantly reduced.

## VI. CONCLUSION

External and internal series in-line switching operations can pose a risk to the security of the sensitively set pilot scheme protection elements. Pros and cons exist for the different solutions that many utilities use in the industry today. Users need to evaluate the need for security, dependability, and simplicity for their respective power system to determine the preferred solution. Recommended guidelines for setting directional element thresholds, as discussed in Section V.A, are useful in addressing the challenge. Only adjusting the thresholds may not cover all cases, as shown with Case Study 1. In addition to the directional element settings, for internal switching events, a good compromise solution can be to use two levels of 67G elements in the pilot scheme, as discussed in Section V.E. A good line switch maintenance program may help ensure that the maximum pole scatter is limited to a range of acceptable delay, avoiding the need for longer time delays for the sensitive element. If this is not possible, one may need to rely on the ground inverse-time overcurrent element to clear the high-resistance fault.

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## VIII. BIOGRAPHIES

**Cobey Bean** joined Oklahoma Gas & Electric in 2002 as a relay technician. After obtaining his B.S. in electrical engineering from the University of Oklahoma in 2010, Cobey moved into the role of maintenance engineer. In 2016, Cobey joined Western Farmers Electric Cooperative as a protection engineer. Presently, his primary area of expertise is transmission and distribution system protection. Cobey is a registered professional engineer in the state of Oklahoma.

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