Line Current Measurement at Dual-Breaker Terminals: Challenges and Solutions

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Line Current Measurement at Dual-Breaker Terminals: Challenges and Solutions

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***Abstract*—This paper describes an event in which a line relay at a dual-breaker terminal operated for a reverse bus fault. The current transformers (CTs) at each breaker were paralleled to measure line current and brought into the relay. Analysis of relay event records showed how CT saturation caused the summed current to not accurately represent the line current. This error caused the relay to see the fault in the forward direction and trip. In this paper, we explain the challenges of measuring line current accurately at dual-breaker terminals and discuss solutions that improve relay security.**

I. Introduction

Distance, directional overcurrent, and line current differential elements are typically used to protect transmission lines, which are some of the most critical assets of a power system. The correct operation of each of these elements is dependent on accurate measurement of the line current.

At line terminals with a single breaker, current transformers (CTs) on the bus side of the breaker directly measure the line current and deliver the data to the relay responsible for protecting the line, as shown in Fig. 1a. At line terminals with two breakers, such as breaker-and-a-half or ring bus configurations, CTs are not placed directly on the line to measure the line current. Instead, the line current is measured using CTs on each breaker, as shown in Fig. 1b. This CT placement maximizes selectivity for a fault on the bus between the two breakers. The measurements from these two sets of CTs must be summed together to arrive at the true line current.

Two methods can be used to sum the currents at dual-breaker terminals. One option is to parallel the CTs and bring the summed measurement into the relay. This is required for relays that have only a single set of three-phase current inputs (such as Relay A in Fig. 1). The other method requires a dual-current input relay (such as Relay B in Fig. 1). A dual-current input relay allows each set of CTs to be wired individually to two separate three-phase current inputs on the relay. The currents from each breaker are then summed mathematically inside the relay to calculate the total line current.

When CTs perform well, both methods described above measure line current accurately. However, when CTs saturate during a reverse fault, the measured line current may not represent the true line current in magnitude and direction. This can occur regardless of which method is used and can compromise the security of the relay.

In this paper, we first explain the situations that can cause this loss of security to occur and describe the impact on line protection elements. Next, we share an event where this exact problem caused a line relay at a dual-breaker terminal to operate for a reverse bus fault. This event is particularly interesting because the primary and backup relays behaved differently. The primary relay (a dual-input relay) remained secure, while the backup relay (a single-input relay with paralleled CTs) operated. We share the analysis that went into understanding the relay operation and arriving at root cause. Finally, we discuss solutions to improve the security of single- and dual-current input relays when these relays are applied to dual-breaker terminals.

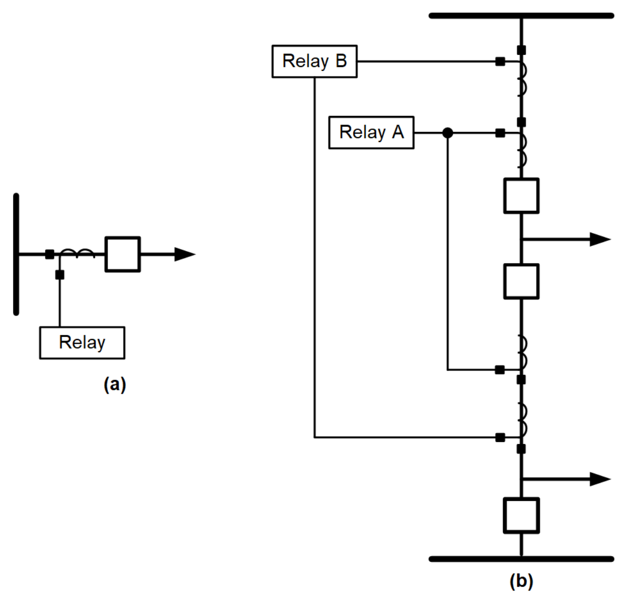

Fig. 1. Single-breaker terminal (a) and dual-breaker terminal (b).

II. The Challenge With Line Current Measurement at Dual-Breaker Terminals

The ability of a relay to accurately measure line current during a fault depends on the performance of the CTs. Measurement is further complicated at dual-breaker terminals because the line current is not a direct measurement. Instead, it is obtained by summing the currents from the CTs of two breakers. In this section, we show how the line current measurement can change during different example conditions and how the resulting error can impact protection elements. We also present criteria that can help protection engineers identify when a relay is at risk in a given line application.

A. *Line Current When CTs Perform Accurately*

In the dual-breaker terminal shown in Fig. 2, Relay A is a single-current input relay connected to paralleled CTs. Relay B is a dual-current input relay that is measuring each CT current individually. For simplicity, all CTs have a 1/1 ratio.

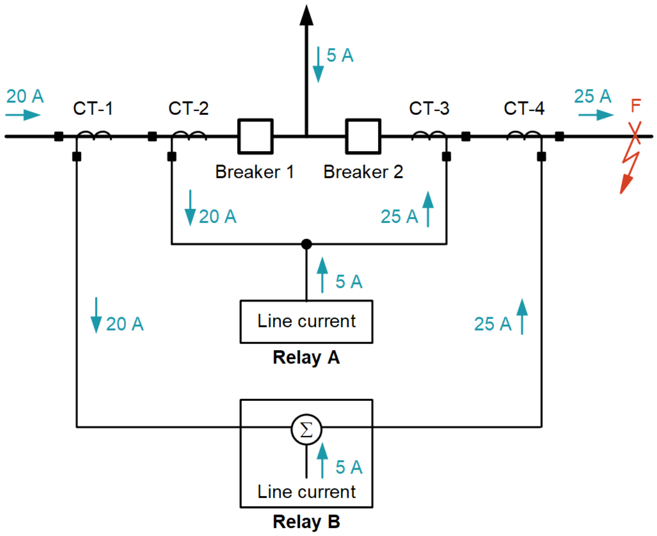

Fig. 2. Single- and dual-current input relays successfully measure line current when CTs perform well.

During a reverse fault on the bus, the current contributed by the remote line terminal is 5 A. If the local terminal were a single-breaker terminal, the relay would be expected to measure a line current of 5 A in the reverse direction, since the fault is external to the zone of protection. For a dual-breaker terminal, the relay would be expected to arrive at the same line current using measurements from CTs at both breakers.

Breaker 1 CTs (CT-1 and CT-2) measure the current contributed from the local source behind Breaker 1 to the fault, which is 20 A in this example. Because the primary current is entering the polarity dots of both CTs, the secondary currents are shown leaving the polarity dots. Breaker 2 CTs (CT-3 and CT-4) measure the total current to the fault, which is 25 A in this example. The total current is the sum of the current contributed from the remote line terminal (5 A) and the current contributed from the local source behind Breaker 1 (20 A). Because the primary current is leaving the polarity dots of the CTs, the secondary currents are shown entering the polarity dots.

Relay A measures the summed current after paralleling CT-2 and CT-3. When we apply Kirchhoff's current law at the point of summation, we see that Relay A measures 5 A. This current is flowing away from the relay, which is the reverse direction. Relay B, on the other hand, is directly connected to CT-3 and CT-4. When we mathematically add both currents inside the relay, we see that Relay B also calculates the line current to be 5 A in the reverse direction. This proves that when CTs at each breaker replicate the primary current correctly, both methods of summation result in the relays measuring the correct line current (in magnitude and direction).

B. *Line Current When CTs Saturate*

CT saturation causes the CTs to incorrectly replicate the primary current, resulting in a secondary current with a lower magnitude and a slightly leading phase angle. Because the reduction in current magnitude has a stronger impact in the examples that follow, the error in phase angle is neglected.

During a reverse fault, CT saturation affects the line current measurement at single- and dual-breaker terminals differently. At single-breaker terminals, a CT directly measures the line current. If the CT saturates, the secondary current has a reduced magnitude, but the line current is still in the reverse direction for a reverse fault.

At dual-breaker terminals, the fact that the line current is not being directly measured can have a detrimental impact on relay security during a reverse fault. The loss in security occurs when a strong local source contributes to the fault and CTs saturate. To understand why, we consider the reverse fault at the dual-breaker terminal in Fig. 2. Here, Breaker 1 CTs measure the current from the local source going to the fault (the through-current). Breaker 2 CTs measure the current from the local source plus the line current. The line current is the difference between Breaker 2 and Breaker 1 currents. As long as Breaker 2 currents are greater than Breaker 1 currents, the direction of the line current is reverse, which is the same direction as the Breaker 2 currents. However, if Breaker 2 CTs saturate (the most likely scenario, since they measure the most fault current), the magnitude of the secondary currents are reduced. This can make Breaker 2 currents lower than Breaker 1 currents, causing the line current to change to the forward direction. This is more likely to occur when the line current is weak. The weak line current makes Breaker 2 currents only slightly greater than Breaker 1 currents, leaving a small margin for error. This means that even a minimal amount of saturation on the Breaker 2 CTs can be enough to change the line current direction. On the other hand, a strong line current makes Breaker 2 currents much greater than Breaker 1 currents. This means that even when Breaker 2 CTs saturate, Breaker 2 currents measured by the relay are still greater than Breaker 1 currents, so the direction of the line current is preserved. We illustrate both of these scenarios in the examples below.

1) *Weak or Open Remote Line Terminal*

In the example shown in Fig. 3, the remote line terminal is considerably weaker than the local source, and Breaker 2 CTs have saturated. The saturation of Breaker 2 CTs results in a reduced output of 10 A on the secondary instead of the expected 25 A. Breaker 1 currents are still 20 A, since those CTs did not saturate. Breaker 2 currents measured by the relay have now become less than Breaker 1 currents. As a result, Relay A measures the sum of CT-2 and CT-3 currents to be 10 A flowing towards the relay, which is considered to be the forward direction. Relay B also produces the same result after mathematically adding CT-1 and CT-4 currents. This example shows how CT saturation combined with a weak remote line terminal has changed not only the magnitude but also the direction of the line current.

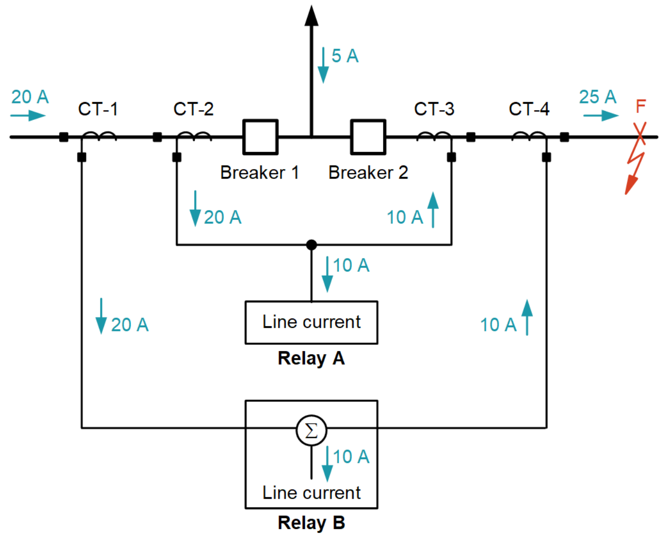

Fig. 3. Saturation of CT-3 and CT-4, combined with a weak remote line terminal, changes the magnitude and direction of the line current measured by Relay A and Relay B.

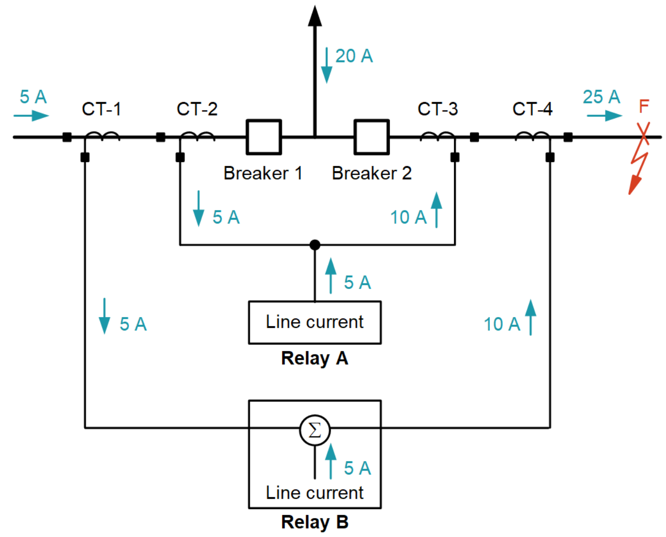

Fig. 4. Saturation of CT-3 and CT-4 changes the magnitude of the line current, but the strong remote line terminal prevents the direction from changing.

When the remote line terminal is open, the same current flows through Breaker 1 and Breaker 2. If the CTs match (same make and model with similar burdens), most of the errors that are due to saturation cancel out, and the measured line current is near zero. Remanence can cause matching CTs to saturate differently. However, remanence is generally short-lived (less than half a cycle) and has little effect on standard protection elements [1]. If the CTs do not match, they saturate differently. The unequal errors do not cancel each other out and instead cause the relay to measure a false line current. This false line current appears in the forward direction if Breaker 2 CTs (which are measuring the reverse current) saturate worse than Breaker 1 CTs.

2) *Strong Remote Line Terminal*

In the example shown in Fig. 4, the remote line terminal is considerably stronger than the local source. The remote line terminal is contributing 20 A to the reverse fault, while the local source is contributing 5 A. The saturation of Breaker 2 CTs results in a reduced output of 10 A on the secondary instead of the expected 25 A. Breaker 1 currents are 5 A, since those CTs did not saturate.

Because the remote line terminal is strong, Breaker 2 currents measured by the relay are still greater than Breaker 1 currents. As a result, Relay A measures the sum of CT-2 and CT-3 currents to be 5 A flowing away from the relay, which is considered to be the reverse direction. Relay B also produces the same result after mathematically adding CT-1 and CT-4 currents. The true line current is 20 A in the reverse direction. This example shows how CT saturation changed the magnitude of the line current, but the strong remote line terminal prevented the direction from changing.

C. *Impact on Line Protection*

An incorrect line current measurement, especially the line current direction, can significantly impact the security of directional, distance, differential, and stub bus protection.

Directional elements compare the angle of the line current to a reference quantity to determine the direction of a fault, as shown in Appendix A. An incorrect current direction measurement causes the directional elements to declare a reverse fault as forward, compromising the security of any element they supervise. For example, a sensitively set directional ground overcurrent element can easily misoperate if the magnitude of the error current is above the pickup setting.

Distance elements calculate an impedance by dividing the voltage by the line current. The relay operates when the impedance is within a defined zone of protection and the phase current exceeds the pickup of the fault detector. Zones 1 and 2 of a distance relay are normally set to look in the forward direction. Zone 1 elements trip the relay instantaneously, while Zone 2 elements trip the relay after a set time delay. Instantaneous Zone 2 elements are often used in communications-assisted tripping schemes to send permission to trip to the remote end of the line or trip the local relay if it is not blocked by the remote end. If the line current direction measurement is incorrect, a reverse fault appears in the forward direction and challenges the security of instantaneous Zone 1 and Zone 2 elements. Time-delayed Zone 2 elements are not a concern, since the primary protection should clear the fault before the time delay has expired.

When the measured line current direction is incorrect, instantaneous Zone 1 elements may pick up and cause a trip, depending on the magnitude of the calculated impedance. Instantaneous Zone 2 elements in a communications-assisted tripping scheme may also pick up. Current reversal logic, usually used to add security in parallel line applications, can be enabled to prevent a misoperation during this condition [2]. This logic extends the relay's reverse decision after the reverse elements drop out. The logic helps in this situation because CTs do not saturate instantaneously after a fault. During the short period of time when the CTs are accurately replicating the primary current, the measured line current is correct, and the directional elements declare a reverse decision. When CTs eventually saturate and cause the line current direction to change, the extended reverse decision prevents the relay from sending permission to trip to the remote end and blocks the local relay from tripping.

Line current differential relays compare the line currents from both terminals to determine if the fault is internal or external to the zone of protection. The relay calculates the ratio of the remote current (I_R) to the local current (I_L). If this ratio plots in the trip region of the alpha plane (shown in Fig. 5) and the difference current is greater than a pickup setting, the relay operates. For example, if Relays A and B in Fig. 3 are line current differential relays, the incorrect line current direction causes the relays to calculate a ratio of I_R/I_L that plots in the trip region of the alpha plane ($0.5\angle 0$ in this example). If the difference current is above the pickup setting, the relays operate.

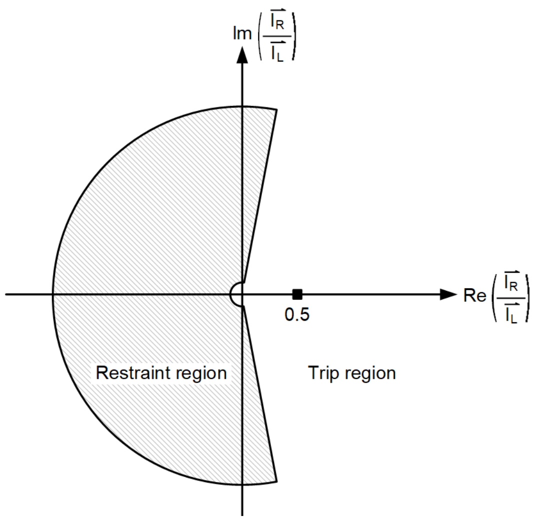

Fig. 5. I_R/I_L plots in the trip region of the alpha plane for the example shown in Fig. 3.

Stub bus protection protects the area between the two breakers and the disconnect switch when the switch is open. One of the protection elements used for stub bus protection is an overcurrent element that responds to the difference current between the CTs of the two breakers [3]. This is simply the line current. For an internal fault on the stub bus, the measured line current is not zero and causes the protection to operate. Under normal load conditions, or during a reverse fault with accurate CT performance the element is secure because the measured line current is zero. However, if the CTs saturate unequally, a false value of line current can cause a misoperation.

D. Criteria for Evaluating Relay Security

In this section, we present criteria that can be used to evaluate if line current measurement at a dual-breaker terminal is at risk of appearing in the forward direction during a reverse fault and causing a misoperation. As explained in Section II.B, this can occur when the remote line terminal is significantly weaker than the local source or when the remote line terminal is open. The potential error from summing the large currents measured by the two CTs at the dual-breaker terminal can be greater than the small line current that the relay is trying to measure.

If the dual-breaker terminal has matching CTs (same make and model with similar burdens), a weak remote line terminal has a bigger impact on line current measurement than an open remote line terminal (as explained in Section II.B). To determine if the remote line terminal is weaker than the local source, the protection engineer can calculate the ratio of the minimum remote line current (when the remote line terminal is closed) to the maximum bus fault current. The maximum bus fault current can be found by placing a fault on the local bus and determining the total current at the fault point. This current is the maximum current that the line CTs can measure during a reverse fault, as explained in [4]. If the ratio is greater than 50 percent (indicating a stronger remote line terminal), then the line current measurement is not at risk.

If the ratio of the minimum remote line current to the maximum bus fault current is less than 50 percent (indicating a weaker remote line terminal), then the CT performance must be evaluated against the relay settings to determine if the line current error has the potential to cause a misoperation.

A CT saturation calculator such as [5] can be used to determine how much the CTs will saturate for the maximum bus fault current. The calculator provides the magnitude of the ideal secondary current and the actual secondary current that would be measured by a relay connected to the CT. The largest difference between the two currents is the maximum CT error. If the necessary inputs to the CT saturation calculator (accuracy class, burden, and X/R ratio) are not available, [4] assumes an error of 50 percent for reasonably sized CTs. The engineer should factor in the CT error and calculate the line current for the maximum reverse bus fault as shown in Fig. 3. If the line current is in the forward direction, the engineer should make sure that it does not exceed the pickups of the instantaneous elements or the distance element fault detectors. If the pickups are exceeded, the engineer should consider implementing the corrective actions outlined in Section V.

If the dual-breaker terminal has mismatched CTs, an open remote line terminal has a bigger impact on line current measurement than a weak remote line terminal for two reasons. First, the unequal CT errors during a reverse fault sum together to create a false line current measurement. Second, because the actual line current is zero, the CT error does not have to override the line current to appear in the forward direction (as is required for a weak remote line terminal). To evaluate the impact of an open remote line terminal on line current measurement and relay security, the engineer should compare the CT performance against the relay settings, as described earlier in this section.

III. The Outage

In this section, we share an event where incorrect line current direction measurement impacted relay security at a dual-breaker terminal. Fig. 6 shows the relevant section of the Lower Colorado River Authority Transmission Services Corporation’s 138 kV transmission system. Substation Alpha consists of two 138 kV buses in a breaker-and-a-half configuration. Line X connects Substation Alpha to Substation Beta, where it terminates at a single breaker.

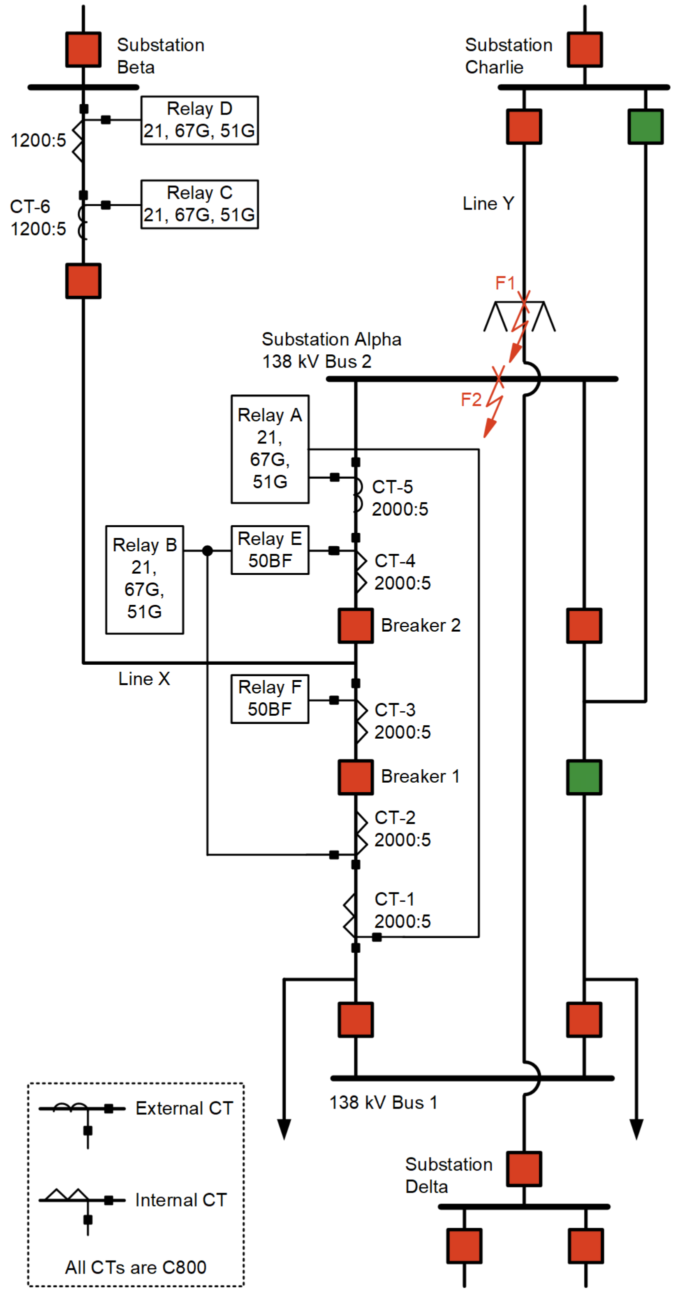

Fig. 6. Simplified one-line diagram.

Line X is protected by primary (Relay A and Relay C) and backup (Relay B and Relay D) microprocessor-based line relays. The relays are programmed to trip on distance (21), directional ground overcurrent (67G), and directional ground inverse-time-overcurrent (51G) elements. In addition, the primary relays are using a directional comparison blocking scheme. Relay E and Relay F are microprocessor-based breaker failure relays.

Line Y is a 138 kV transmission line connecting Substation Charlie to Substation Delta. This line physically passes over Substation Alpha and is supported by structures in the substation.

On September 8, 2018 at 11:50 a.m., the A-phase of Line Y was struck by lightning. The strike caused the failure of an insulator on one of the structures supporting the line as it passed through Substation Alpha. The result of the insulator failure is shown in Fig. 7.

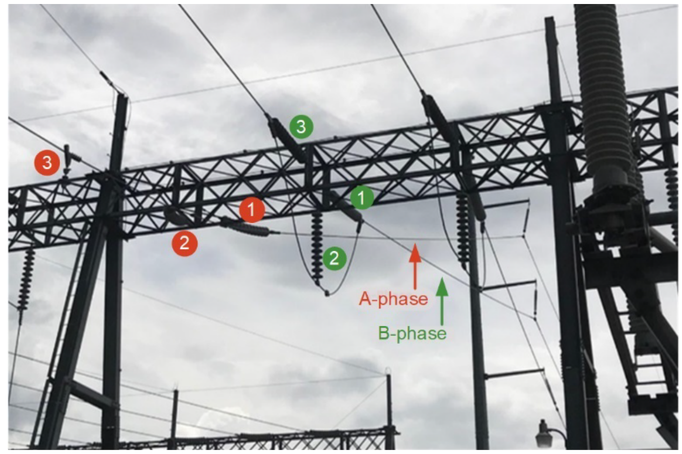

Fig. 7. Failed Insulator 3 on the structure supporting Line Y in Substation Alpha.

The insulators on the structure supporting the A-phase are labeled in red, and the insulators supporting the B-phase are labeled in green. The B-phase is unfaulted and provides a good reference for comparison. The B-phase conductor is properly supported by Insulators 1, 2, and 3 as the conductor passes over the substation. Due to the lightning strike on the A-phase, Insulator 3 has broken off, and Insulator 2 is being pulled forward by the tension on the conductor. The failure of Insulator 3 resulted in a ground fault from the A-phase to the structure, shown as Fault F1 in Fig. 6. The relaying on Line Y operated correctly for the fault and tripped. The relay at Substation Delta automatically reclosed, but tripped to lockout due to the permanent fault.

When Insulator 3 failed completely, the overhead phase conductor was no longer properly supported, and the extra slack caused the conductor to drop and make contact with the C-phase busbar below it, as shown in Fig. 8.

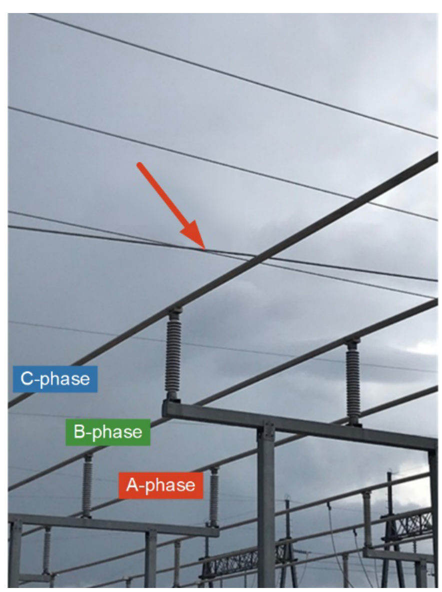

Fig. 8. Line Y makes contact with the C-phase of Bus 2.

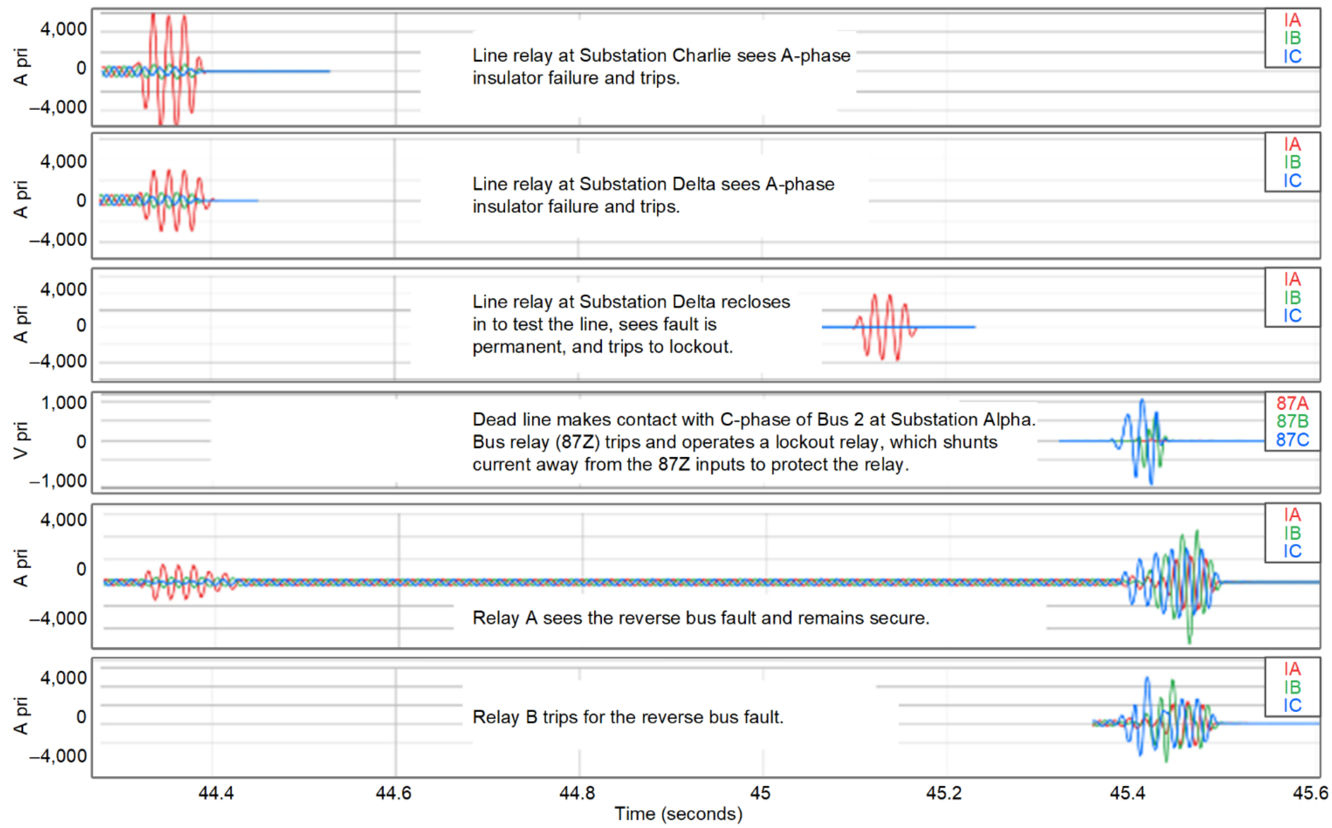

Fig. 9. Sequence of events on common time scale.

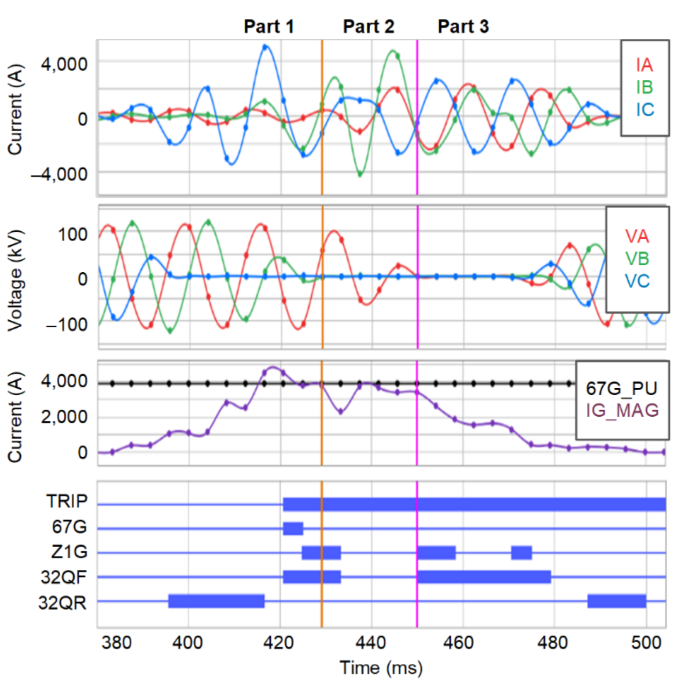

Fig. 10. Filtered event report from Relay B.

This happened approximately 200 ms after the overhead line was de-energized (from the relay at Substation Delta going to lockout). The de-energized conductor created a path to ground from the busbar in Fig. 8 to the structure supporting the line in Fig. 7, causing Fault F2 in Fig. 6. When this happened, the high-impedance bus differential relay (87Z) protecting Bus 2 operated correctly and tripped, but the backup line relay (Relay B) on Line X also tripped. The primary line relay (Relay A) remained secure. Fig. 9 shows the sequence of events from the relays on a common time scale.

In summary, the fault was initially on Line Y, and the relaying for that line tripped correctly. When the failed insulator caused the de-energized line to fall on the bus, it created a C-phase-to-ground (C-G) fault on the bus. The bus relay tripped correctly for this fault. The relaying on Line X, however, did not behave correctly. The primary relay (Relay A) remained secure by not tripping for the reverse bus fault. The backup relay (Relay B) tripped incorrectly. The utility questioned the operation of Relay B.

IV. Event Report Analysis

Immediately after the event, we began analyzing the event reports from Relay A and Relay B to try to understand why one relay operated correctly while the other did not.

A. Analysis of Relay B Event

The filtered event report from Relay B is shown in Fig. 10. Most of our attention immediately went to analyzing the operation of this relay, since it operated incorrectly. The current and voltage waveforms throughout this event are particularly interesting. In the first part of the fault, the C-phase current is high and the C-phase voltage is near zero, indicating a close-in C-G fault. In the second part of the fault, the B-phase voltage also drops to zero, indicating that the fault has evolved to a B-C-G fault. In the third part of the fault, the A-phase voltage also drops to zero, indicating that the fault has evolved to a three-phase fault. Either the conductor that initially landed on the C-phase of the bus made contact with the other two phases shortly thereafter, or the ion cloud created by the initial fault caused the other two phases to also fault. Note that we needed to use the voltages to determine the fault types during the second and third parts of the fault because the currents did not match what was expected for these fault types. This observation called into question the validity of the current signals.

The event report shows that the relay tripped on the directional ground overcurrent element (67G) during the first part of the fault. The magnitude of the measured ground current (4,500 A primary) exceeded the pickup setting of the 67G element (3,880 A primary). The Zone 1 ground distance element (Z1G), which was set to cover 85 percent of the line, also asserted shortly thereafter. Both the 67G and Z1G elements require the fault to be seen in the forward direction to operate. Since we knew that the fault was behind the relay (on Bus 2 at Substation Alpha), this appeared to be a misoperation. If the direction had been declared correctly as reverse, neither of these elements would have asserted. This led us to further analyze the behavior of the directional elements.

Relay B uses the negative-sequence directional element (32Q) to supervise the ground distance and ground overcurrent elements. Appendix A describes how this element works. The 32QF and 32QR logical bits show the relay's directional element decision. The 32QF bit asserts when the fault is seen in the forward direction, and the 32QR bit asserts when the fault is seen in the reverse direction. At the beginning of the fault, when the voltages and currents agreed that the fault was C-G, the relationship between I_2 and V_2 is shown in Fig. 11a. This matches the relationship for a reverse fault (shown in Appendix A). Therefore, the 32QR bit asserted. As the fault evolved and the current signals no longer matched the fault type, the relationship between I_2 and V_2 changed to that shown in Fig. 11b. This matches the relationship for a forward fault (shown in Appendix A). Therefore, the 32QF bit asserted. This change to the forward direction caused the 67G element to assert and the relay to trip. It also allowed the Z1G element to assert. This analysis tells us that the relay's directional decision was correct based on the signals that it measured.

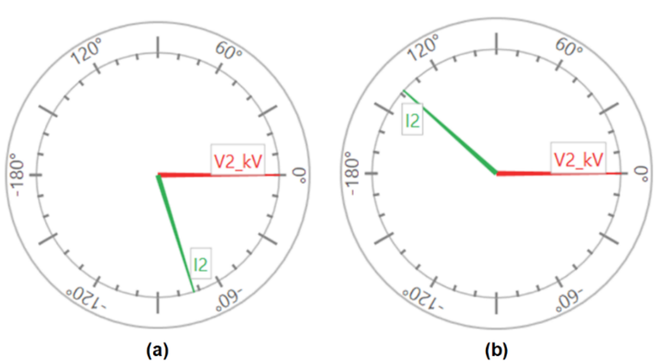

Fig. 11. I_2 versus V_2 as the measured current changes from reverse (a) to forward (b).

B. *Analysis of Relay A Event*

Next, we looked at the filtered event report from Relay A, which is shown in Fig. 12. Relay A was set to trip on the same Z1G and 67G elements (with the same settings) as Relay B, so we questioned why it failed to trip for this fault.

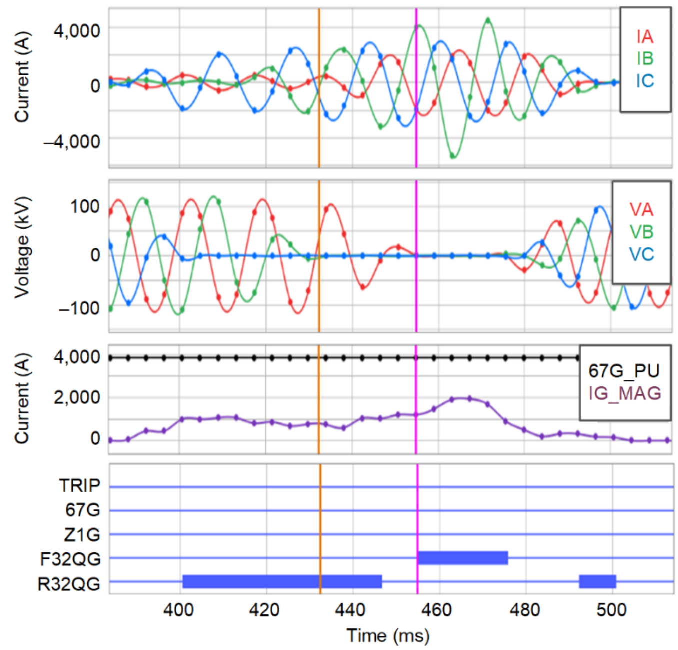

Fig. 12. Filtered event report from Relay A.

The first thing that stood out was that, although the voltage waveforms from Relay A looked exactly the same as those from Relay B, the currents did not match at all. We also noticed that the ground current that Relay A measured for the same fault was only 1,980 A primary, which is less than half of what Relay B measured. Because the ground current was below the 67G pickup, the relay never operated. The Z1G element also did not pick up. In addition, we noticed that the current waveforms did not match the fault type for the second and third parts of the fault.

In this relay, the F32QG bit asserts when the fault is seen in the forward direction, and the R32QG bit asserts when the fault is seen in the reverse direction. Just like Relay B, Relay A initially saw the fault correctly in the reverse direction and changed its decision to forward as the fault evolved. The only reason Relay A did not also trip on 67G was because the ground current was below the pickup value.

After analyzing event reports from Relay A and Relay B, we noted two important things. First, the currents measured by both relays did not match each other. Fig. 13 compares the individual phase currents from Relay A with those of Relay B. We can see that the A-phase currents match, but the B- and C-phase currents differ greatly. These are primary and backup relays for the same line, and the voltages and currents they measure should always be the same. This difference in currents is what caused the backup relay to operate and the primary relay to restrain. Second, neither of the relays measured currents that consistently matched the fault type. It seemed as if neither relay was measuring the line current correctly. Therefore, our next question was, what was the actual line current?

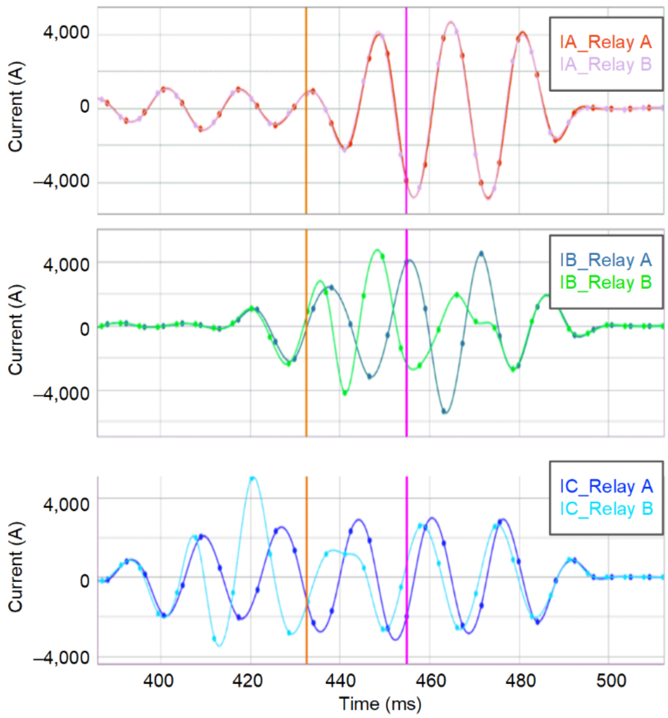

Fig. 13. Relay A versus Relay B currents.

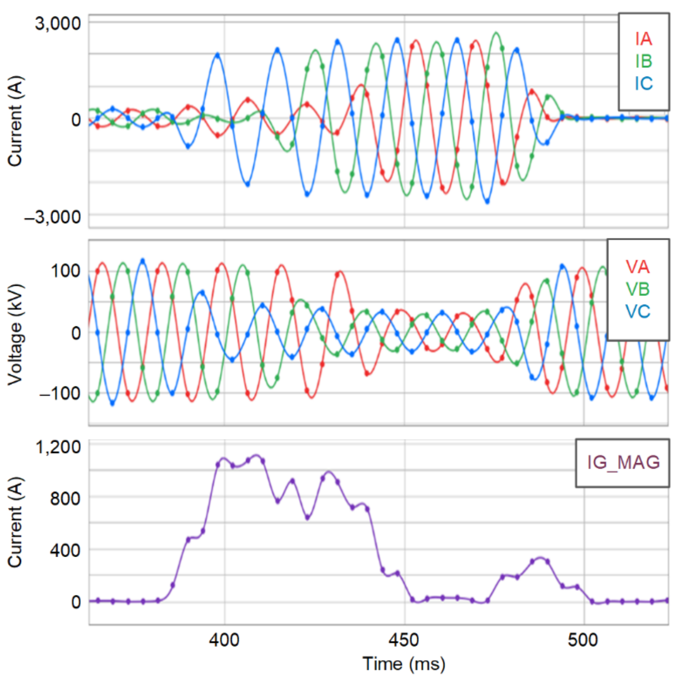

Fig. 14. Filtered event report from Relay C.

C. *What Was the Actual Line Current?*

As a reference, we looked at the event report from Relay C, which was on the other end of the line. This report is shown in Fig. 14. The currents represent the contribution by the remote line terminal to the fault and are the actual currents that were on the line. These waveforms correlate to what we would expect for the fault type and do not show the distortion that we saw on the relays at the other end of the line. The fault started out as a C-G fault. Within 1.5 cycles, the fault evolved to include the B-phase, and within another 1.5 cycles, it evolved further to include all three phases. We noticed that the ground current was significant during the beginning of the fault, but as the fault evolved into a three-phase fault, it reduced to almost zero (as expected). We discuss the importance of this in the next subsection.

D. *Why Did Relay B Not Measure the True Line Current?*

We noted in Section IV.B that there were errors in the currents seen by both Relay A and Relay B. Relay B was our first focus because it was the relay that operated for the reverse bus fault. Comparing the currents measured by Relay B to the reference at the other end of the line (Relay C), we saw that the current measured by Relay B did not represent the true line current. To determine what could have corrupted the current measurements at Relay B, we first looked at the accuracy classes of the CTs involved. Relay B was receiving current measurements from C800, 2000/5 full ratio CTs. Relay C was receiving current measurements from C800, 2000/5 CTs tapped at 1200/5. Using the tapped ratio on Relay C reduced the CT accuracy class to an equivalent C480. This told us that, out of the two relays, Relay B was using CTs with a higher accuracy class.

Next, we looked at how the two relays were measuring line current. Relay C was located at a single-breaker terminal where a single set of CTs measured the line current. Relay B, on the other hand, was located at a breaker-and-a-half terminal where a set of CTs from each breaker were paralleled to measure the line current. In Section II.B, we discussed that if CTs are paralleled and one or both CTs saturate during a through fault, the summed current may not represent the actual line current. Furthermore, if the current contributed by the local source is stronger than the current contributed by the remote line terminal, and the CT carrying the line current saturates, the direction of the summed secondary current may reverse. We needed to determine if the above conditions were true at the time of the fault.

1) *Was the Local Source Stronger Than the Remote Line Terminal?*

Fig. 14 already showed us the contribution from the remote line terminal to the fault. Looking at the system configuration and the location of the Fault F2 in Fig. 6, we knew that the event captured by Relay F would show the current contributed by the local source, i.e., the source behind CT-1. This event report is shown in Fig. 15.

When we compared the fault current magnitude in Fig. 15 (local source) to Fig. 14 (remote line terminal), we could tell that the local source was significantly stronger than the remote line terminal (13,000 A versus 1,000 A during the C-G fault). Due to the open breakers in Fig. 6, all of the local contribution to the fault had to flow through Breaker 1, making the Breaker 1 current significantly stronger than the current from the remote line terminal. In addition to the phase currents, Fig. 15 also shows the magnitude of the ground current calculated during the fault. The significance of the ground current is explained next.

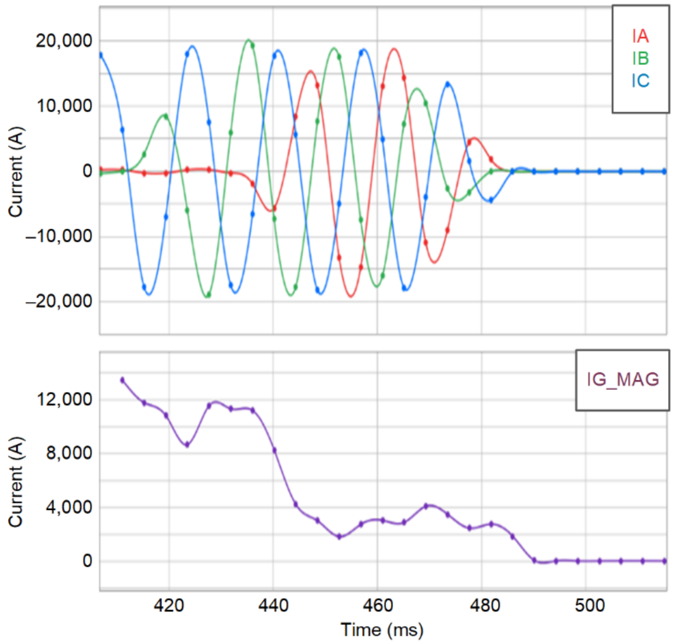

Fig. 15. Filtered event report from Relay F.

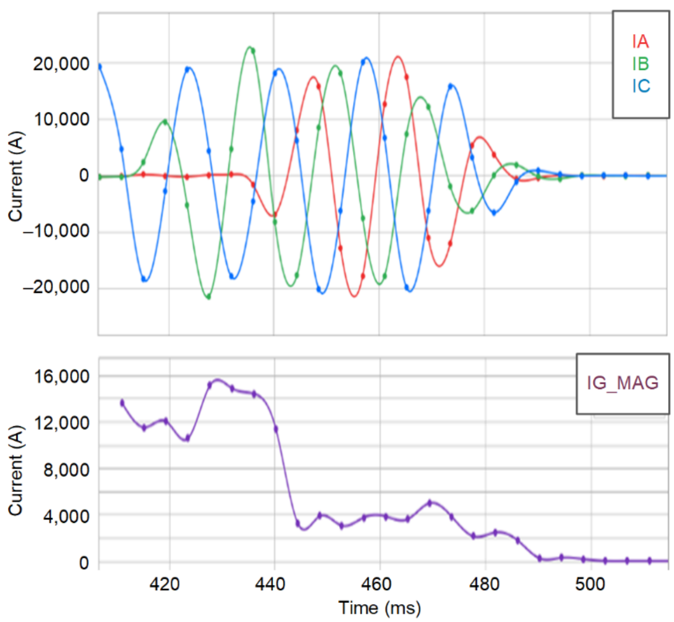

Fig. 16. Filtered event report from Relay E.

2) Did the CTs Saturate?

Next, we determined whether any of the CTs that were paralleled to Relay B (CT-2 or CT-4 in Fig. 6) saturated during the fault. To do this, we needed to look at the secondary currents from each of the two CTs. Unfortunately, Relay B did not give us this information because it only measured the summed current. We needed to use data recorded by other relays to know what the individual CTs were measuring.

Fig. 6 showed that CT-4 was wired to Relay E before being paralleled with CT-2. The filtered event report captured by Relay E during the fault is shown in Fig. 16. The phase currents in this event report represent the total current to the fault (the summation of the current contributed by the local source and the remote line terminal). To determine if CT-4 saturated during this fault, we needed the raw event report, as filtered event reports filter out the harmonics and DC offset that are characteristic signatures of CT saturation [6]. Unfortunately, only the filtered event reports had been downloaded from the relays before they were overwritten with newer events.

Since the raw data were not available, other methods had to be used to detect CT saturation using filtered event reports. One method involves looking for false ground current: ground current that does not make sense for the fault type [6]. The ground current in Fig. 16 shows a perfect example of this. We expected to see ground current during the beginning of the event report (a C-G fault that evolved into a B-C-G fault). Then, at around 445 ms, when all three phases became involved in the fault, we expected to see the ground current drop to near zero. (In Fig. 14, Relay C did not measure any ground current during the three-phase portion of the fault.) Contrary to expectations, Relay E measured significant ground current during this time. We suspected that this ground current did not actually exist on the system, but was caused by CT saturation. If any of the three phase CTs saturate, the relay calculates a false ground current due to the unbalance among the phases.

Next, we shifted our focus to CT-2. Unlike CT-4, this CT was not connected to any other relay before being paralleled. However, CT-2 currents could be easily derived by subtracting Relay E currents from Relay B currents. The derived CT-2 currents matched the currents recorded by Relay F (Fig. 15), indicating similar performance from both CT-2 (Relay B) and CT-3 (Relay F). Fig. 15 shows significant ground current during the three-phase portion of the fault, indicating that both CT-2 and CT-3 saturated during the fault.

3) Why Did the CTs Saturate?

There are two types of CT saturation: symmetrical saturation and asymmetrical saturation. Symmetrical saturation occurs when the magnitude of the primary current is too large for the CT core to handle. Asymmetrical saturation is not caused by the magnitude of the primary current, but by the presence of significant dc offset in the primary current. Symmetrical saturation normally occurs within the first half-cycle after fault inception, while asymmetrical saturation can take several cycles to occur. A CT experiencing symmetrical saturation can come out of saturation only if the fault current magnitude decreases. A CT experiencing asymmetrical saturation can come out of saturation as the dc offset in the primary current decays [6].

With this background in mind, we compared the line currents measured by Relay B to Relay C on a per-phase basis, as shown in Fig. 17. (Relay C currents have been flipped by 180 degrees to make it easier to see the difference between the two currents.) Relay C was our reference since it was the relay that measured the line current correctly. We saw that when the fault began as a C-G fault, the C-phase currents were completely equal to each other (which was expected). However, at 404 ms, the C-phase current measured by Relay B no longer represented the actual line current. At 450 ms, the C-phase current measured by Relay B recovered to match the actual line current. Similarly, when the B-phase first got involved in the fault, the B-phase currents were completely equal to each other. However, at 433 ms, the B-phase current measured by Relay B no longer represented the actual line current. At 475 ms, toward the end of the fault, the B-phase current measured by Relay B recovered to match the actual line current. In contrast, after the A-phase got involved in the fault, the A-phase current measured by Relay B matched the actual line current throughout the duration of the fault.

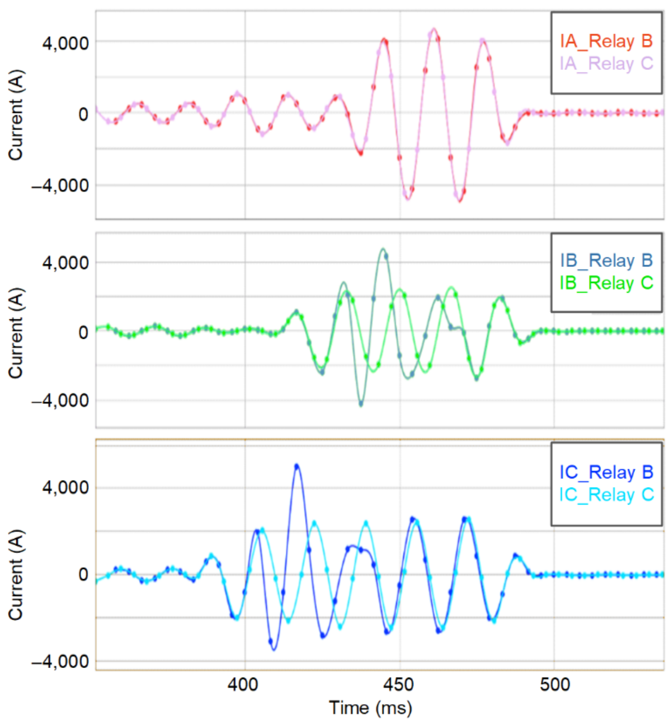

Fig. 17. Relay B versus Relay C currents.

We drew a few conclusions from this analysis. First, the B- and C-phase CTs connected to Relay B did not saturate within the first half-cycle of the fault inception. Second, these CTs eventually came out of saturation. Third, when the A-phase got involved and created a three-phase fault, the A-phase CT measured the same current as the B- and C-phase CTs but never saturated. Based on these three observations, we suspected that the presence of dc offset in the B- and C-phase primary currents caused asymmetrical CT saturation.

4) Summary

Our summary of why Relay B did not measure the actual line current and how this caused it to operate for an out-of-zone fault is as follows: first, when the fault occurred, CT-2 measured the current contributed by the local source to the fault. This current entered the polarity side of the CT. CT-4 measured the line current in addition to the current contributed by the local source. This current entered the non-polarity side of the CT. If the CTs had performed correctly, the CT-4 current would have been higher and in an opposite direction than CT-2. When CT-2 and CT-4 currents were summed, the result would be the line current in the correct direction (the same as CT-4).

Unfortunately, both CTs saturated. We suspect that the presence of dc offset in the B- and C-phase primary currents caused asymmetrical CT saturation. Furthermore, for the same amount of dc offset in the primary current, we expected that CT-4 would saturate worse than CT-2, because it was carrying more current and therefore was already closer to saturation. Because the line current was weak (weak remote line terminal) and CT-4 saturated worse than CT-2, CT-4 currents became lower than CT-2 currents and caused the summed current to change to the forward direction, the same as CT-2. (This behavior was explained in detail in Section II.B.1.) Relay B, operating on the summed current, made a forward directional decision for the reverse fault and tripped the line when the ground current exceeded the 67G pickup setting. This decision was correct based on the signals that it measured.

E. Why Were Relay A Currents Different From Relay B Currents?

Relay A and Relay B were both measuring the line current at the dual-breaker terminal. We explained in the previous section why the Relay B currents did not match the actual line current. The Relay A currents also did not match the actual line current for the same reason, even though Relay A was a dual-current input relay. Having CT-1 and CT-5 connected to separate current inputs on Relay A was no different than paralleling CT-2 and CT-4 externally to Relay B, as described in Section II. Even though Relay A was not measuring the line current correctly, it was expected to measure the same currents as Relay B. However, Fig. 13 showed that Relay A and Relay B currents were not the same. The only explanation for this is that the Relay A and Relay B CTs must have saturated differently.

There are several factors that can cause CTs to saturate differently for the same fault. The first factor is that the CTs may have a different accuracy class or ratio. In this case, both relays were using C800 CTs with 2000/5 ratios, so this could not be the reason for the difference in saturation.

The second factor is how the CTs are connected to the relay. There is a concern that paralleling CTs to a single-current input relay (Relay B) increases the burden on the CTs, as opposed to connecting them individually to a dual-current input relay (Relay A). Fig. 18 shows CTs paralleled to a single-current input relay. The figure includes the individual CT burdens as well as the common burden. The common burden is a summation of the impedance of the leads from the paralleled point to the relay and the impedance of the relay input itself. When the CTs are paralleled at the relay control panel, the length (and therefore impedance) of the leads from the paralleled point to the relay is small. The impedance of the relay input in a microprocessor-based relay is also small. Therefore, the summed common burden is usually negligible. Equation (1) gives the burden seen by CT_1 in Fig. 18. When CTs are paralleled, the common burden gets multiplied by a factor that includes the infeed from the other CTs. When the common burden is negligible, which was the case in this example, the change in burden due to paralleling CTs is negligible.

Therefore, this could not be the reason why the Relay A and Relay B CTs saturated differently.

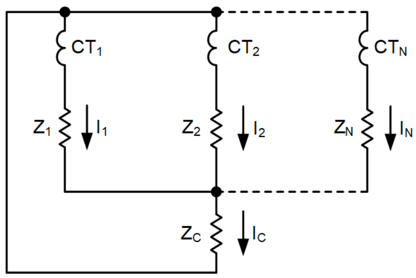

Fig. 18. CTs paralleled to a single-current input relay [7].

$$Z_{CT_1} = Z_1 + Z_C \left[\frac{I_1 + I_2 + \ldots I_n}{I_1} \right] \tag{1}$$

The third factor is remanence [6]. In this case, the CTs that are on the same breakers (CT-1 and CT-2 on Breaker 1, and CT-4 and CT-5 on Breaker 2) would always experience the same fault current and develop the same remanence. Furthermore, the effects of remanence only persist for half a cycle. Since both sets of CTs performed poorly for more than half a cycle, we know that remanence did not cause them to saturate differently.

The fourth factor is the CTs having different excitation curves. To determine if this played a role, we compared the performance of CT-1 (Relay A) with CT-2 (Relay B) and CT-5 (Relay A) with CT-4 (Relay B). CT-1 and CT-2 are both in the same breaker. These CTs have the same make and model, measure the same fault current, and have similar burdens. This leads us to conclude that CT-1 and CT-2 saturated similarly during the fault. When comparing CT-5 with CT-4, CT-5 is an externally mounted slip-over CT while CT-4 is an internal bushing CT (see legend in Fig. 6). These CTs are made by two different manufacturers, which means that even though both CTs are classified as C800, their internal construction may be completely different. One CT may be built with more copper and less iron while the other may be built with more iron and less copper, leading to completely different excitation curves as demonstrated in [6]. Although the excitation curves for these CTs were not available, it was reasonable for us to assume that this was why CT-5 saturated differently than CT-4, which resulted in Relay A measuring a different current than Relay B.

V. Corrective Actions

As we described in Section IV, Relay B tripped because its CTs saturated during the reverse bus fault, causing the summed line current to appear in the forward direction. In this section, we consider several corrective actions that would prevent the relay from operating in such a scenario.

A. Properly Select CTs

Relays require accurate current measurements from CTs to operate correctly. Therefore, it is critical to ensure that the CTs are sized to perform well under various fault conditions on the power system. In this case, the CTs connected to Relay B were both C800 and were tapped at their maximum ratio of 2000:5. Equation (5) in [6] can be used to determine if a higher-ratio CT would have performed better under the given conditions. In addition to saturation, other factors that should be considered when selecting CTs for line applications are explained in [4] and [8]. In some applications, asymmetrical saturation is inevitable even after responsibly selecting CTs. For this particular installation, the utility chose to explore other options that would allow them to continue using their existing CTs.

B. Use Relay Settings to Add Security to Instantaneous Protection Elements

When CT saturation is a concern at a dual-breaker terminal, relay settings must be selected to match the expected CT performance. Reference [9] explains how to secure line current differential elements during this condition. Reference [10] explains how to secure overcurrent elements used for stub bus protection. Section II.C of this paper describes how instantaneous Zone 2 elements used in communications-assisted tripping schemes can be secured with current reversal logic. In this section, we focus on how to secure Zone 1 distance and instantaneous directional ground overcurrent elements.

1) Zone 1 Distance Elements

When the local source is significantly stronger than the remote line terminal, the line current for a forward fault in Zone 1 is significantly higher than that for a reverse fault. This difference in line current magnitude can be used to differentiate between a forward and reverse fault and keep the relay secure. Zone 1 distance elements (phase and ground) have built-in fault detectors that require a minimum level of fault current to allow operation. Reference [11] provides guidance on how to set the fault detectors. At a dual-breaker terminal, additional security can be added by making sure that the pickup is set above the maximum fault current contributed by the remote line terminal during a reverse fault. This ensures that the Zone 1 distance element does not misoperate when the line current measurement changes direction. In the case study presented in this paper, the Zone 1 ground fault detector was set to 200 A primary, which is much less than the 1,000 A contributed by the remote line terminal for this fault. Raising the fault detector pickup setting would have helped keep the Zone 1 ground element secure.

2) 67G Element

One option to secure the 67G element uses the principles introduced in [4] for securing transformer relays at dual-breaker terminals. In [4], the security of the unrestrained differential element (87U) is challenged by the same problem described in Section II of this paper. The proposed solution involves setting the 87U pickup above the maximum reverse current (the maximum bus fault current) multiplied by an expected percent CT error. The same principle can be used here to secure the 67G element. A high-set instantaneous 67G element can be set above the maximum bus fault current multiplied by an expected percent CT error. An additional 67G element with a more sensitive pickup (set following the guidelines of [11]) can be added with a small 1 to 2 cycle time delay. Since most reasonably-rated CTs will saturate due to dc offset, the time delay allows for that offset to decay and the CTs to come out of saturation.

A second solution is to set a single 67G element with a sensitive pickup (following [11]) and an adaptive time delay. The element is instantaneous if the current reversal logic has not asserted. However, if the current reversal logic picks up (meaning a reverse fault has been detected and saturation may be expected), the element is delayed by 1 to 2 cycles.

A third solution is to remove the 67G element and rely on a directional residual inverse-time overcurrent element (51G) for detecting ground faults. The 51G element trips faster for high-magnitude internal faults and slower for low-magnitude currents, such as those produced by asymmetrical CT saturation. As in the previous solutions, the time delay allows the element to ride through asymmetrical saturation until the CT recovers.

C. Use a Dual-Current Input Relay With Added Security Logic

In Section IV, we saw that a relay with dual-current inputs sums the current from the two CTs no differently than if the CTs were paralleled external to the relay. Simply wiring the individual CTs into the relay does not solve the problem. However, measuring individual CT currents gives us the ability to enhance security of line protection elements for the type of fault discussed in this paper. One way to enhance security is to use the reverse fault security logic described in this section. The main benefit of this solution is that it avoids having the engineer raise pickup settings or add time delays to the instantaneous elements to maintain security.

1) Description of Reverse Fault Security Logic

The reverse fault security logic proposed in [12] detects a reverse fault at a dual-breaker terminal and blocks the instantaneous protection elements in the relay from causing a trip. When a reverse fault occurs, current through one or both of the breakers is in the reverse direction (see Fig. 3). In contrast, when a forward fault occurs, current through both breakers (if closed) is in the forward direction. This difference allows the logic to differentiate between forward and reverse faults.

Fig. 19 shows the reverse fault security logic. The output of the logic (REV_FLT_BLK) can be used to block instantaneous protection elements in the trip logic. There are two main parts of the logic: REV_FLT and FWD_FLT. REV_FLT asserts when any of the phase currents from Breaker 1 or Breaker 2 are in the reverse direction. This indicates the presence of a reverse fault, and REV_FLT immediately blocks tripping by asserting REV_FLT_BLK. If a reverse fault is detected for more than 0.75 cycles, the block is extended by an additional 2.5 cycles after dropout.

FWD_FLT is used to remove the block and allow the instantaneous protection elements to operate when a fault evolves from reverse to forward. If this forward decision is detected for more than 0.25 cycles, REV_FLT_BLK deasserts and allows the relay to trip if the instantaneous protection elements pick up. The FWD_FLT logic asserts when the directional logic for one breaker declares forward and the directional logic for the other breaker (on the same phase) does not declare reverse. This accounts for when both breakers are closed, or when one of the breakers is open or has a weak source.

The logic in Fig. 19 uses separate directional decisions for each phase. This is done to maintain dependability if there is an external fault on one phase and a simultaneous internal fault on another phase. Phase directional elements are used to make the directional decisions. One type of phase directional element that can be used is described in Appendix A. This element calculates a torque-like product to determine direction. A positive value corresponds to the forward direction and a negative value corresponds to the reverse direction.

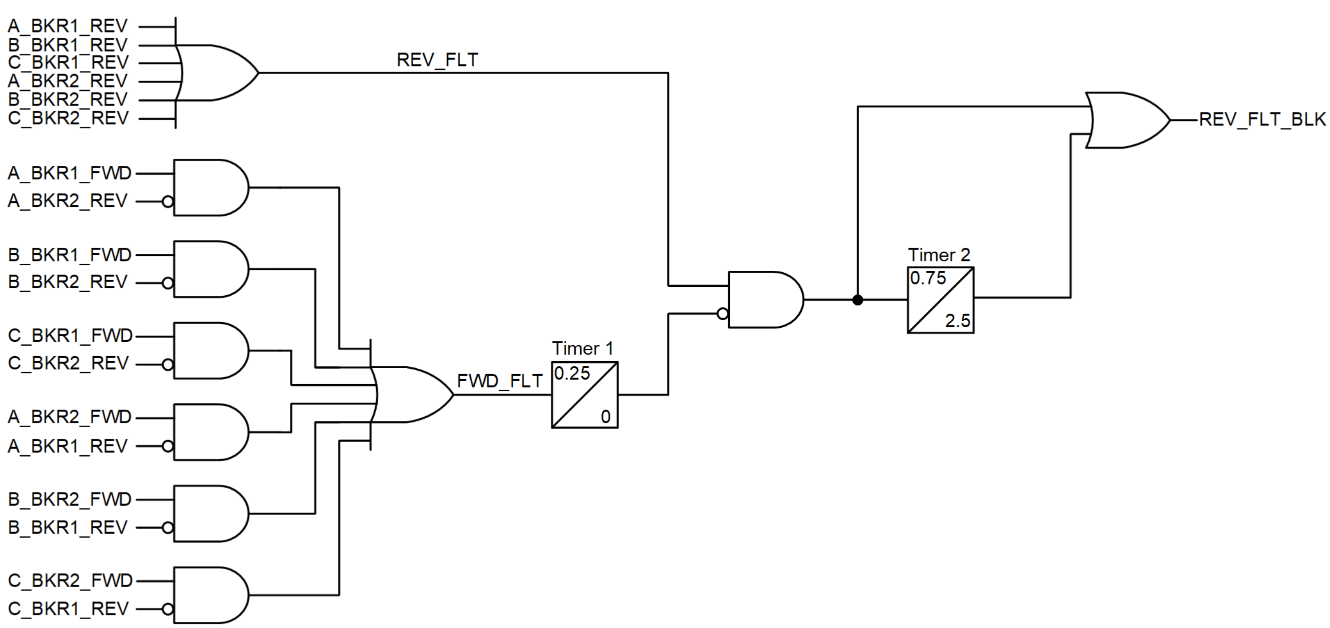

Fig. 19. Reverse fault security logic in dual-current input relays.

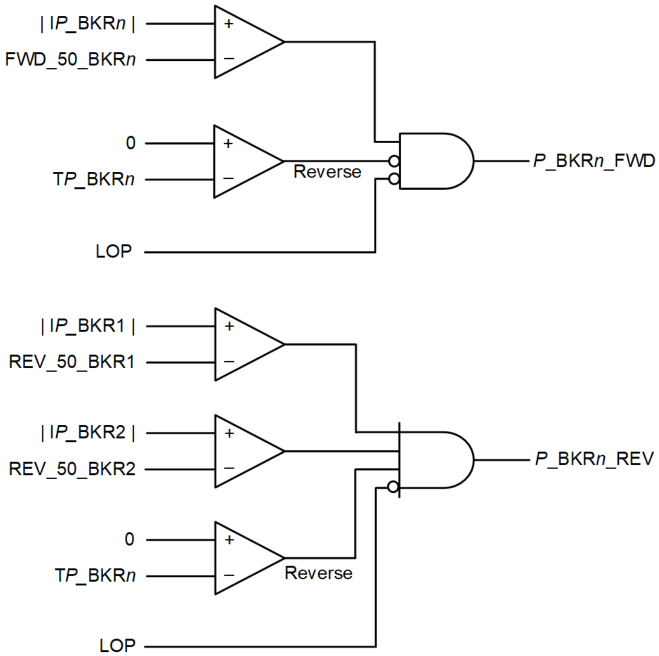

Fig. 20. Forward and reverse directional decisions for Phase *P* on Breaker *n*.

Fig. 20 shows how the phase directional elements are combined with additional supervision to make the directional decision that is used in the reverse fault security logic. Three requirements must be met for the logic to declare a forward fault. First, the magnitude of the faulted phase current must be greater than the FWD_50_BKR*n* setting. Reference [12] recommends setting this to 2 to 3 times the nominal current to detect faults in the forward direction. Second, the phase directional element must not declare a reverse fault. The forward logic is used to unblock REV_FLT_BLK during reverse-to-forward evolving faults. Therefore, using the inverse of the phase directional element's reverse decision is preferred over using the forward decision to ensure dependability should the fault evolve from reverse to forward and the torque-like product evaluates to zero. Third, there must not be a loss of potential (LOP) condition. This means that the voltage measurement required by the phase directional element is valid.

Similar to the forward fault logic, three requirements must be met for the logic to declare a reverse fault. First, the faulted phase current magnitude must be above the REV_50_BKR*n* setting on both breakers. Second, the phase directional element must declare a reverse fault. Third, LOP must be deasserted.

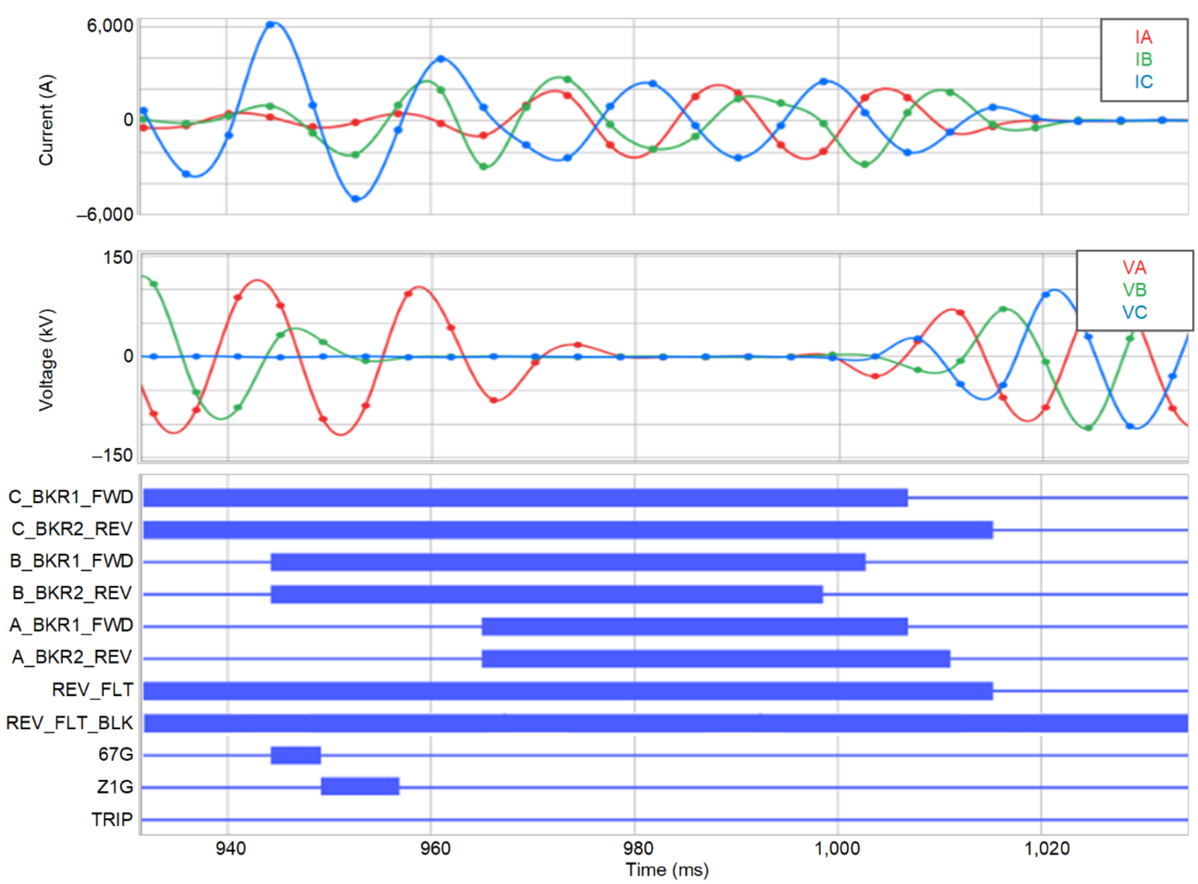

Fig. 21. REV_FLT_BLK asserts during the fault and blocks the relay from tripping.

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Reference [12] recommends setting REV_50_BKR*n* to 1.5 to 2 times the nominal current to ensure that there is a fault and both breakers are closed. If one of the breakers is open, the line current is being directly measured and supervision from the reverse fault security logic is not required. The REV_50_BKR*n* pickup setting is set more sensitive than the FWD_50_BKR*n* pickup setting to maintain security when there is a reverse fault, the remote line terminal is open, and currents through both breakers are the same. If the forward and reverse pickups are the same and measurement errors occur, the directional logic for the breaker closest to the fault may not declare a reverse decision while the directional logic for the other breaker declares forward. A lower pickup ensures that the reverse logic for the breaker closest to the fault asserts in this case.

The reverse fault security logic described in this section can be implemented in firmware or user-programmable logic in a microprocessor-based dual-current input relay. It can be used to supervise Zone 1 distance, ground directional overcurrent, or stub bus protection elements. Although this logic can also be used to supervise line current differential elements, these elements use a different principle that allows the individual breaker currents to increase security during reverse faults with CT saturation. For more information on this, refer to [13], [14], and [9].

2) Implementation of Reverse Fault Security Logic

We programmed the reverse fault security logic in a dual-current input relay, as shown in Appendix B. We supervised the ground directional overcurrent element and the Zone 1 ground distance element in the relay's trip logic with NOT REV_FLT_BLK. The next step was to play back the fault seen by Relay B, as that was the relay that had tripped. Since the Relay B event report only contained the summed currents (because the CTs were paralleled), we used the event reports from Relay E and Relay F to obtain the individual breaker currents for the test.

Fig. 21 shows the relay's response to the fault after adding the reverse fault security logic. When the fault first began as a C-G fault, the C-phase Breaker 1 logic declared a forward direction, while the C-phase Breaker 2 logic declared a reverse direction. The same decisions were made for the B-phase and A-phase when the fault evolved to those phases. REV_FLT asserted when the first reverse decision was made (C-phase) and caused REV_FLT_BLK to assert. As a result, even though 67G and Z1G picked up, REV_FLT_BLK prevented the relay from tripping.

VI. Conclusion

Directional overcurrent, distance, and line current differential relays all rely on the accurate measurement of line current to operate properly. The accuracy of this line current measurement can be compromised at dual-breaker terminals. Unlike at single-breaker terminals, the relays at dual-breaker terminals are not directly measuring the line current. Instead, the line current is obtained by summing the currents from the CTs on each breaker. The summation is done by either paralleling the CTs to a single-current input relay or by connecting them individually to a dual-current input relay and summing them mathematically inside the relay.

The security of line protection elements is challenged when a reverse fault occurs, the CTs saturate, the local source is strong, and the remote line terminal is weak or open. When all of these conditions are true, it is possible for the summed line current to not represent the true line current in magnitude and direction. This incorrect line current measurement, especially the line current direction, can cause a reverse fault to appear as forward and can result in the operation of instantaneous protection elements that are set sensitively in the forward direction. The incorrect line current measurement can occur regardless of whether the CTs are paralleled to a single-current input relay or connected individually to a dual-current input relay. The criteria outlined in Section II.D can be used to identify when a relay is at risk for a given line application.

In this paper, we showed how this exact problem caused a line relay at a dual-breaker terminal to operate for a reverse bus fault. Analysis of relay event reports showed that when the CTs replicated the primary current correctly, the line current measurement was accurate and in the reverse direction. When the CTs saturated, the line current measurement became inaccurate, and the direction changed from reverse to forward. This change in direction allowed a sensitively set ground directional overcurrent element, as well as a Zone 1 ground distance element, to assert and cause a trip.

Because the error in line current measurement exists only when CTs saturate, correctly selecting CTs minimizes the likelihood of this problem occurring. If saturation is inevitable, Zone 1 distance elements can be secured by raising the pickup of the corresponding fault detectors. One option to secure the 67G element is to implement an instantaneous element with a pickup above the error current along with a more sensitively set element with a small time delay. Alternatively, the 67G element can be set with a fixed pickup and a time delay that adapts based on the status of the pilot scheme current reversal logic. A directional 51G element can also be used in place of the 67G element to ride through small amounts of false ground current during asymmetrical saturation while still providing fast tripping for high magnitude internal ground faults.

All of the above solutions require the engineer to fine-tune relay settings to balance sensitivity and security. To avoid having to make these compromises, engineers can use a dual-current input relay with reverse fault security logic. The benefit of a dual-current input relay is that it has access to the individual breaker currents that make up the line current. These currents are used by the reverse fault security logic to make directional decisions at each breaker. If a forward directional decision is declared by both breakers, the reverse fault security logic declares a forward fault. If a reverse directional decision is declared by one or both breakers, the reverse fault security logic declares a reverse fault. The reverse decision of the reverse fault security logic can be used to block the instantaneous elements in the relay trip equation.

VII. Appendix A: Review of Directional Elements

Directional elements are used to determine if a fault is located in front of (Location F1) or behind (Location F2) a relay, as shown in Fig. 22. Directional elements are often used to supervise overcurrent and distance elements. In their most basic form, directional elements respond to the phase angle difference between a polarizing quantity and an operating quantity. These quantities can vary with the type of directional element, but the polarizing quantity is always the reference and should be selected to be stable and reliable during forward and reverse faults.

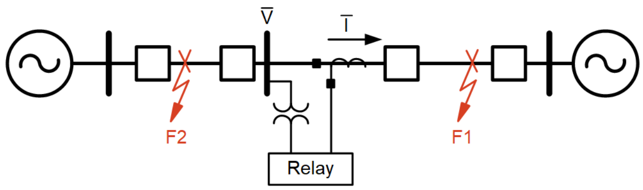

Fig. 22. Forward and reverse faults.

This appendix briefly describes the two types of directional elements used in this paper. The first type is a negative-sequence voltage-polarized element (32Q). This element is used by Relay A and Relay B to determine the direction of ground faults (as discussed in Section IV). The second type is a phase directional element that determines the direction of each phase independently. This element is used by the reverse fault security logic (described in Section V.C) to detect reverse faults at dual-breaker terminals.

A. Negative-Sequence Voltage-Polarized Element

The negative-sequence voltage-polarized directional element (32Q) uses negative-sequence voltage (V_2) and negative sequence current (I_2) to operate. Because it uses negative-sequence quantities, it is the most widely used directional element to determine direction of unbalanced faults (phase-to-ground, phase-to-phase-to-ground, and phase-to-phase faults). The phase relationship between V_2 and I_2 for forward and reverse faults is shown in Fig. 23 and derived in [15].

B. Phase Directional Element

This element determines the direction of the fault by comparing the phase angle of the faulted phase current to the phase angle of the unfaulted phase-to-phase voltages. A torque-like product is calculated for each phase using the equations in (2) below.

$$\begin{aligned} T_A &= |V_{BC}| \cdot |I_A| \cdot \cos(\angle V_{BC} - \angle I_A) \\ T_B &= |V_{CA}| \cdot |I_B| \cdot \cos(\angle V_{CA} - \angle I_B) \\ T_C &= |V_{AB}| \cdot |I_C| \cdot \cos(\angle V_{AB} - \angle I_C) \end{aligned} \quad (2)$$

V_{AB}, V_{BC}, and V_{CA} are the polarizing quantities, and I_A, I_B, and I_C are the operating quantities. A positive value indicates forward direction, and a negative value indicates reverse direction for each phase. For more details on how this element works, refer to [16] and [17].

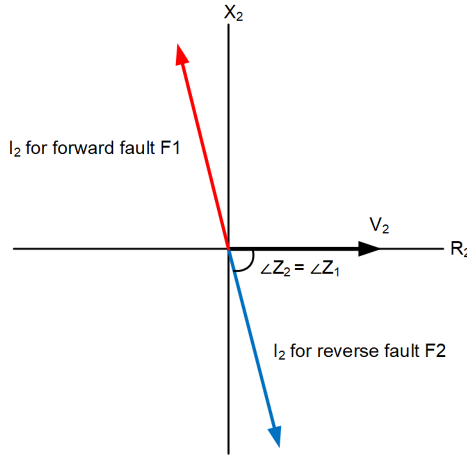

Fig. 23. I_2 versus V_2 for forward and reverse faults, where $\angle Z_2$ and $\angle Z_1$ are the angles of the negative- and positive-sequence line impedances.

This element works well for close-in phase-to-ground faults because the voltages used are from the unfaulted phases. It also works well for close-in phase-to-phase and phase-to-phase-to-ground faults because one of the phase voltages will always be from an unfaulted phase. However, in the case of a close-in three-phase fault, all three voltages can go to zero and cause all three torque-like products to evaluate to zero, resulting in no directional decision.

To avoid this problem, it is possible to incorporate memory into the polarizing voltage quantity. This is done using (3), where n is the present sample and $n - 1$ is the previous sample. We then replace V_{BC}, V_{CA}, and V_{AB} in (2) with V_{BC_mem}, V_{CA_mem}, and V_{AB_mem} from (3).

$$\begin{aligned} V_{BC\_mem}{}^{n} &= \frac{1}{16} V_{BC}{}^{n} + \frac{15}{16} V_{BC\_mem}{}^{n-1} \\ V_{CA\_mem}{}^{n} &= \frac{1}{16} V_{CA}{}^{n} + \frac{15}{16} V_{CA\_mem}{}^{n-1} \\ V_{AB\_mem}{}^{n} &= \frac{1}{16} V_{AB}{}^{n} + \frac{15}{16} V_{AB\_mem}{}^{n-1} \end{aligned} \quad (3)$$

The memory voltage calculation combines a large portion of the previous voltage with a small portion of the present voltage. This allows the memory voltage to decay slowly when the present voltage drops immediately to zero during a close-in three-phase fault. The slow decay gives the element time to make a directional decision before voltage is completely lost.

Another way to write (2) is using the real and imaginary components of the operating and polarizing quantities, as shown in (4). For ease of implementation, we used this format when programming the directional elements in the reverse fault security logic described in Section V.

$$\begin{aligned} T_A &= \mathrm{Re}(V_{BC\_mem}) \cdot \mathrm{Re}(I_A) + \mathrm{Im}(V_{BC\_mem}) \cdot \mathrm{Im}(I_A) \\ T_B &= \mathrm{Re}(V_{CA\_mem}) \cdot \mathrm{Re}(I_B) + \mathrm{Im}(V_{CA\_mem}) \cdot \mathrm{Im}(I_B) \\ T_C &= \mathrm{Re}(V_{AB\_mem}) \cdot \mathrm{Re}(I_C) + \mathrm{Im}(V_{AB\_mem}) \cdot \mathrm{Im}(I_C) \end{aligned} \quad (4)$$

VIII. Appendix B: Implementation of Reverse Fault Security Logic

The code below shows how we programmed the reverse fault security logic described in Section V.C in a dual-current input relay. The output of this logic is a digital quantity (DIG15), which can be used to block distance, directional overcurrent, and stub bus protection elements in the trip logic.

```
############################################
# REVERSE FAULT SECURITY LOGIC #
############################################

# USER SETTINGS
# SETTINGS
ANA01 := 400.000000 #CTR_BKR1
ANA02 := 400.000000 #CTR_BKR2
ANA03 := 1200.000000 #PTR
ANA04 := 1.000000 #INOM
ANA05 := 2.000000 * ANA04 # FWD_50_BKR1
ANA06 := 1.500000 * ANA04 # REV_50_BKR1
ANA07 := 2.000000 * ANA04 # FWD_50_BKR2
ANA08 := 1.500000 * ANA04 # REV_50_BKR2
#
# DEFINITIONS
# VAB
ANA09 := ANA13 # VAB REAL N-1
ANA10 := ANA14 # VAB IMAG N-1
ANA11 := VA_REAL - VB_REAL # VAB REAL N
ANA12 := VA_IMAG - VB_IMAG # VAB IMAG N
ANA13 := (1.000000 / 16.000000) * ANA11 + (15.000000 / 16.000000) * ANA09 # VAB REAL MEM
ANA14 := (1.000000 / 16.000000) * ANA12 + (15.000000 / 16.000000) * ANA10 # VAB IMAG MEM
#
# VBC
ANA15 := ANA19 # VBC REAL N-1
ANA16 := ANA20 # VBC IMAG N-1
ANA17 := VB_REAL - VC_REAL # VBC REAL N
ANA18 := VB_IMAG - VC_IMAG # VBC IMAG N
ANA19 := (1.000000 / 16.000000) * ANA17 + (15.000000 / 16.000000) * ANA15 # VBC REAL MEM
ANA20 := (1.000000 / 16.000000) * ANA18 + (15.000000 / 16.000000) * ANA16 # VBC IMAG MEM
# VCA
ANA21 := ANA25 # VCA REAL N-1
ANA22 := ANA26 # VCA IMAG N-1
ANA23 := VC_REAL - VA_REAL # VCA REAL N
ANA24 := VC_IMAG - VA_IMAG # VCA IMAG N
ANA25 := (1.000000 / 16.000000) * ANA23 + (15.000000 / 16.000000) * ANA21 # VCA REAL MEM
ANA26 := (1.000000 / 16.000000) * ANA24 + (15.000000 / 16.000000) * ANA22 # VCA IMAG MEM
#
```

```
# PHASE DIRECTIONAL ELEMENT TORQUE EQUATIONS FOR BKR1
ANA27 := ANA19*IA_BKR1_REAL + ANA20*IA_BKR1_IMAG # TA_BKR1
ANA28 := ANA25*IB_BKR1_REAL + ANA26*IB_BKR1_IMAG # TB_BKR1
ANA29 := ANA13*IC_BKR1_REAL + ANA14*IC_BKR1_IMAG # TC_BKR1
#
# PHASE DIRECTIONAL ELEMENT TORQUE EQUATIONS FOR BKR2
ANA30 := ANA19*IA_BKR2_REAL + ANA20*IA_BKR2_IMAG # TA_BKR2
ANA31 := ANA25*IB_BKR2_REAL + ANA26*IB_BKR2_IMAG # TB_BKR2
ANA32 := ANA13*IC_BKR2_REAL + ANA14*IC_BKR2_IMAG # TC_BKR2
#
# PHASE DIRECTIONAL DECISIONS BKR1
# FWD
DIG01 := IA_BKR1_MAG > ANA05 AND NOT (ANA27 < 0.000000) AND NOT LOP # A_BKR1_FWD
DIG02 := IB_BKR1_MAG > ANA05 AND NOT (ANA28 < 0.000000) AND NOT LOP # B_BKR1_FWD
DIG03 := IC_BKR1_MAG > ANA05 AND NOT (ANA29 < 0.000000) AND NOT LOP # C_BKR1_FWD
# REV
DIG04 := IA_BKR1_MAG > ANA06 AND IA_BKR2_MAG > ANA08 AND (ANA27 < 0.000000) AND NOT LOP # A_BKR1_REV
DIG05 := IB_BKR1_MAG > ANA06 AND IB_BKR2_MAG > ANA08 AND (ANA28 < 0.000000) AND NOT LOP # B_BKR1_REV
DIG06 := IC_BKR1_MAG > ANA06 AND IC_BKR2_MAG > ANA08 AND (ANA29 < 0.000000) AND NOT LOP # C_BKR1_REV
#
# PHASE DIRECTIONAL DECISIONS BKR2
# FWD
DIG07 := IA_BKR2_MAG > ANA07 AND NOT (ANA30 < 0.000000) AND NOT LOP # A_BKR2_FWD
DIG08 := IB_BKR2_MAG > ANA07 AND NOT (ANA31 < 0.000000) AND NOT LOP # B_BKR2_FWD
DIG09 := IC_BKR2_MAG > ANA07 AND NOT (ANA32 < 0.000000) AND NOT LOP # C_BKR2_FWD
# REV
DIG10 := IA_BKR1_MAG > ANA06 AND IA_BKR2_MAG > ANA08 AND (ANA30 < 0.000000) AND NOT LOP # A_BKR2_REV
DIG11 := IB_BKR1_MAG > ANA06 AND IB_BKR2_MAG > ANA08 AND (ANA31 < 0.000000) AND NOT LOP # B_BKR2_REV
DIG12 := IC_BKR1_MAG > ANA06 AND IC_BKR2_MAG > ANA08 AND (ANA32 < 0.000000) AND NOT LOP # C_BKR2_REV
#
DIG13 := DIG04 OR DIG05 OR DIG06 OR DIG10 OR DIG11 OR DIG12 # REV_FLT
DIG14 := (DIG01 AND NOT DIG10) OR (DIG02 AND NOT DIG11) OR (DIG03 AND NOT DIG12) OR (DIG07 AND NOT DIG04) OR
(DIG08 AND NOT DIG05) OR (DIG09 AND NOT DIG06) # FWD_FLT
#
TIM01PU := 0.250000 # TIMER 1 PICKUP (CYCLES)
TIM01DO := 0.000000 # TIMER 1 DROPOUT (CYCLES)
TIM01IN := DIG14 # TIMER 1 INPUT
TIM02PU := 0.750000 # TIMER 2 PICKUP (CYCLES)
TIM02DO := 2.500000 # TIMER 2 DROPOUT (CYCLES)
TIM02IN := NOT TIM01OUT AND DIG13 # TIMER 2 INPUT
DIG15 := (NOT TIM01OUT AND DIG13) OR TIM02OUT # REV_FLT_BLK
```

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X. Biographies

Michael Lampe received his BSE in electrical engineering from the University of Texas at Austin in 2015. He is a licensed professional engineer in the state of Texas and currently works at the Lower Colorado River Authority in Austin, Texas, with a focus on system protection.

Genardo Corpuz received his BSE in electrical engineering from the University of Texas at Austin in 2005. He is a licensed professional engineer in the state of Texas and currently works at the Lower Colorado River Authority in Austin, Texas. His work experience includes substation design and system protection.

Swagata Das earned her B.Tech degree from SRM University in Chennai, India in 2009. She graduated with her MSE and PhD degrees in electrical engineering from the University of Texas at Austin in 2011 and 2015, respectively. Swagata joined Schweitzer Engineering Laboratories, Inc. (SEL) in 2015 and works as a protection application engineer in Fair Oaks Ranch, Texas. She received the Walter A. Elmore Best Paper Award from the Georgia Institute of Technology Protective Relaying Conference in 2017.

Ariana Hargrave earned her BSEE, magna cum laude, from St. Mary’s University in San Antonio, Texas, in 2007. She graduated with a master of engineering degree in electrical engineering from Texas A&M University in 2009, specializing in power systems. Ariana joined Schweitzer Engineering Laboratories, Inc. (SEL) in 2009 and works as a senior protection application engineer in Fair Oaks Ranch, Texas. She has published over 30 application guides and technical papers and was honored to receive the Walter A. Elmore Best Paper Award from the Georgia Institute of Technology Protective Relaying Conference in 2017 and 2018. She is a senior IEEE member and a registered professional engineer in the state of Texas.

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