Distance Element Improvements – A Case Study

David Costello and Karl Zimmerman
Schweitzer Engineering Laboratories, Inc.

Revised edition released May 2008

Previously presented at the
62nd Annual Georgia Tech Protective Relaying Conference, May 2008

Originally presented at the
61st Annual Conference for Protective Relay Engineers, April 2008

Distance Element Improvements – A Case Study

David Costello and Karl Zimmerman, *Schweitzer Engineering Laboratories, Inc.*

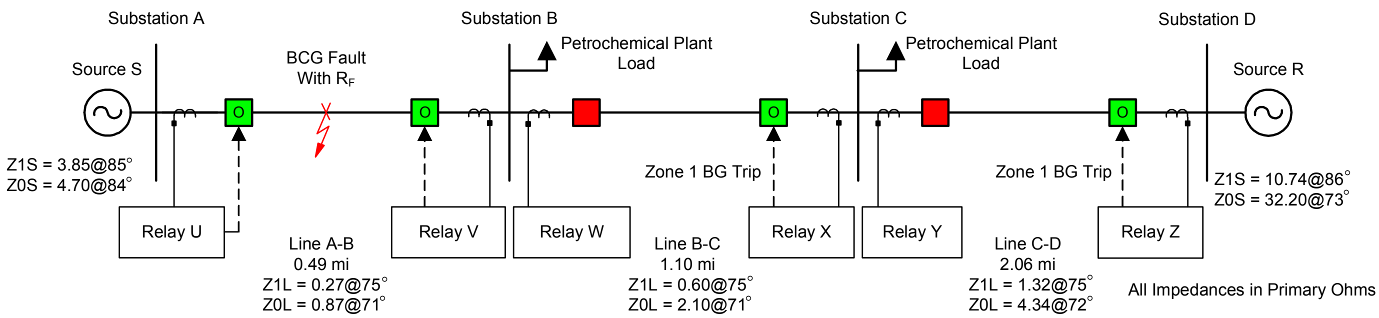

Fig. 1. Case Study One-Line Diagram

***Abstract*—In August 1999, a thunderstorm and lightning strike caused relay misoperations and a two-minute outage at a petrochemical plant. The outage led to an exhaustive root-cause analysis and subsequent litigation. This paper shares details about the event and its root cause, contrasts distance and fault identification algorithms, demonstrates methodical analysis techniques, and proposes solutions. This paper also highlights that engineers face the challenge of always staying current with their experience and understanding of the "state-of-the-art." The paper challenges engineers to do the right thing, find root cause, and solve problems.**

"Discourage litigation. Persuade your neighbors to compromise whenever you can. Point out to them how the nominal winner is often a real loser—in fees, expenses, and waste of time. As a peacemaker, the lawyer has a superior opportunity of being a good man. There will still be business enough. Never stir up litigation. A worse man can scarcely be found than one who does this."

—July 1, 1850; *Abraham Lincoln* [1]

I. Nomenclature

AB, BC, CA, AG, BG, and CG indicate fault types. Additionally, these refer to impedance elements, or loops, within a relay.

Apparent impedance measured by an element may be plotted on an R-X impedance diagram. Additionally, it may be expressed as a number or torque-like product (or more simply, torque). Lower torque is analogous to apparent impedance plotting further from the origin of the R-X diagram. Higher torque is analogous to apparent impedance nearer to the origin.

ABG, BCG, and CAG indicate double line-to-ground fault types.

II. Introduction

In August 1999, a thunderstorm and lightning strike caused a BCG fault with fault resistance (R_F) on a 138 kV transmission system. Refer to Fig. 1 for the one-line diagram. The fault occurred on Line A-B.

All the relays shown in Fig. 1 are of the same make and model, a 1980s-era microprocessor-based relay. The two relays closest to the fault, Relays U and V, operated correctly and as expected to de-energize and quarantine the faulted portion of the power system.

An ethylene and polyethylene (petrochemical) plant is served from Substations B and C. For this fault, the petrochemical plant was expected to have temporarily lost one source, Source S, but remain energized and in operation by service from Source R. However, Relays X and Z operated unexpectedly during the fault. Each of these relays identified the fault as Zone 1 BG and operated with no intentional time delay. Zone 1 would normally indicate that a fault was not located beyond the remote line terminal.

This resulted in the de-energization of Substations B and C and the petrochemical plant shutdown. The outage lasted for two minutes. Reduced plant production rates were endured because start-up procedures took several days to complete.

An investigation of the relay misoperations began immediately. Engineers from the local utility and the relay manufacturer cooperated and determined the root cause of the relay overreach. These engineers identified short- and long-term solutions and began implementing both solutions immediately. The short-term solution involved performing system fault studies and changing a single setting in each relay. Long-term solutions involved upgrading to newer relay technology (available since 1993) that offered significant performance improvements.

The petrochemical plant, on the other hand, chose to sue the local utility and the relay manufacturer for several million dollars. Litigation proceedings lasted for almost eight years, and settlements were reached before the case went to trial. During litigation, the petrochemical plant alleged gross negligence on the part of the utility and the manufacturer. Further, the petrochemical plant alleged that a product problem (polypropylene capacitor drift), which was explained in a service bulletin sent by the manufacturer to affected customers, was the cause of the relay misoperation—it was not. System modeling, relay testing, and event data validate the true root cause and disprove capacitor drift as a culprit.

III. Distance Element Improvements

Self-polarized mho elements implemented in traditional (typically, electromechanical) relays have a reach setting Zr, which represents the diameter of a circular characteristic passing through the origin on the R-X plane. These elements offer no expansion for R_F coverage and are not reliable for zero-voltage faults.

Traditional elements with cross-polarization expand toward the source impedance during faults. This improves R_F coverage. However, these elements are also unreliable during zero-voltage, three-phase faults.

Positive-sequence memory polarization implemented in traditional relays provides reliable operation for zero-voltage faults until the polarizing memory expires (typically 2 to 3 cycles). These elements also expand in proportion to the source impedance to provide the greatest R_F coverage. See Fig. 2.

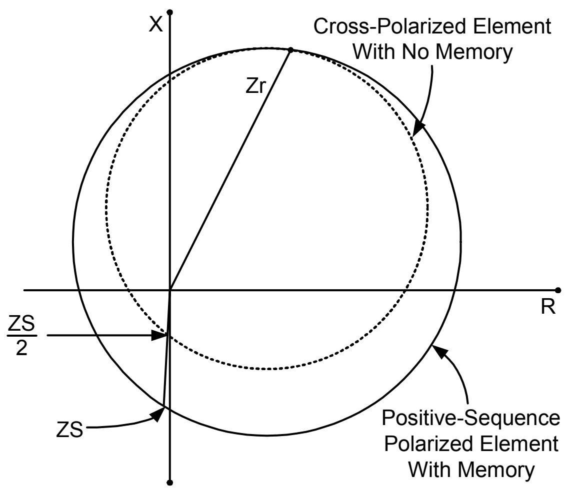

Fig. 2. Phase-to-Phase Element Response for a Forward Phase-to-Phase Fault

While expanded and dynamic mho elements offer better R_F sensitivity, they are also more likely to operate for unintended fault types as compared to self-polarized mho elements.

To illustrate how uninvolved phase and ground distance elements pick up for an AG fault on a radial system, consider Fig. 3. Fault location and fault impedance are varied. For each fault simulation, the torques for six Zone 3 elements (AB, BC, CA, AG, BG, CG) are calculated. The Zone 3 reach is set to 300% of the line impedance.

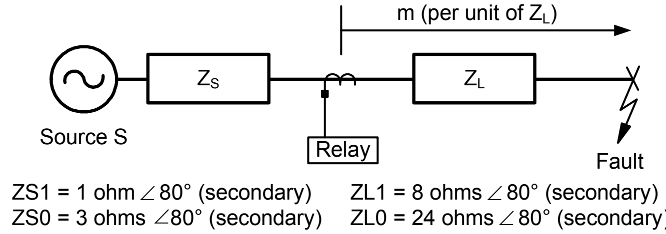

Fig. 3. Example One-Line Illustrating Distance Element Response for an AG Fault

The first step is to place an AG fault at the local bus (m = 0), vary the R_F from 0 to 4 ohms secondary, and plot the results. Fig. 4 shows the results of this exercise.

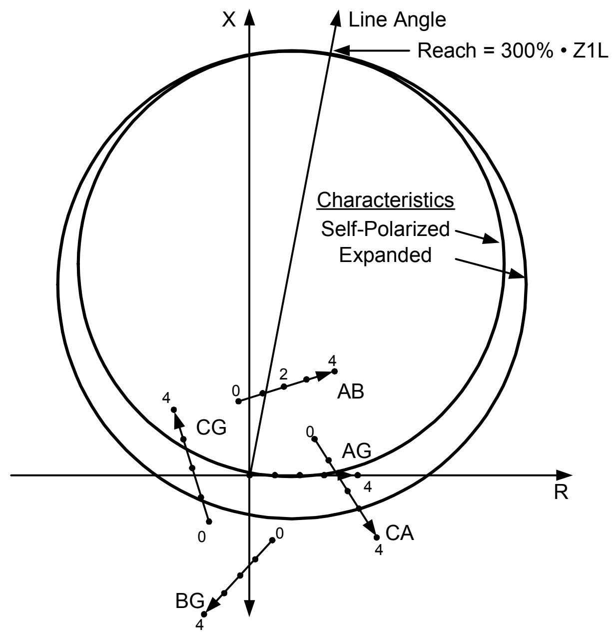

Fig. 4. Apparent Impedances Seen By Varying R_F for a Close-In AG Fault

Several observations can be made from Fig. 4. Multiple distance elements detect the AG fault when R_F = 0. Also, the number of elements that detect the fault varies with R_F.

The second step is to vary the distance to the fault from m = 0 to m = 1 (100% of the protected line). In this step, R_F is not considered. Fig. 5 shows the results of this exercise.

Several observations can be made from Fig. 5. All distance elements involved with A-phase pick up for AG faults near the bus. As the fault location is moved away from the local bus, the torque produced by these elements decreases. For a fault at m = 1, only the AG element detects the fault.

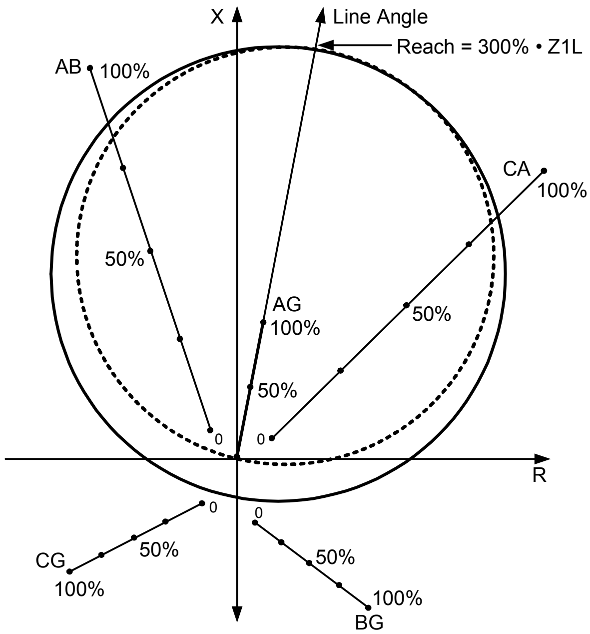

Fig. 5. Apparent Impedances Seen By Varying Fault Location (Without R_F)

Fig. 6 superimposes Figs. 4 and 5. This illustrates a portion of the fault condition spectrum that causes apparent impedance for an AG fault to be seen by multiple mho elements.

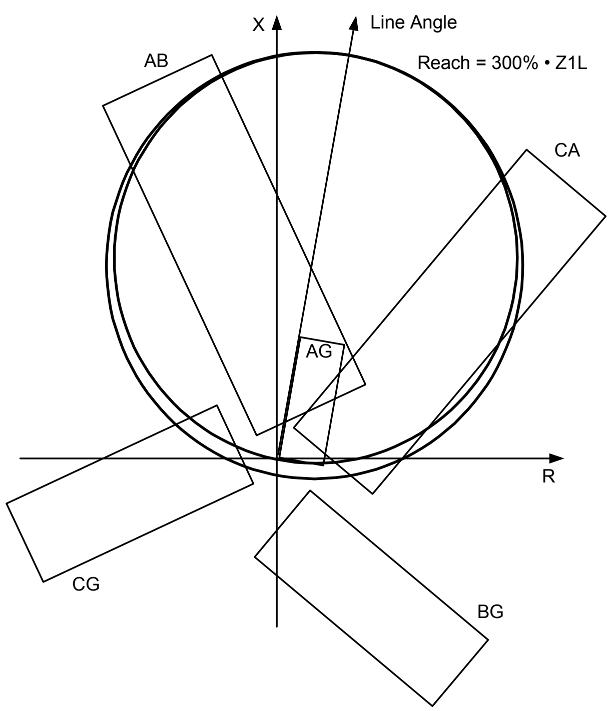

Fig. 6. Fig. 4 and Fig. 5 Superimposed

A variety of methods have been used to correctly identify the fault type and enable appropriate elements for operation. In single-pole applications, the correct faulted phases must be identified and opened (phase-phase elements must be blocked for single line-to-ground faults). In all applications, it is important that distance elements not overreach. For double line-to-ground faults (e.g., BCG) with R_F, the ground element associated with the leading phase (BG) tends to overreach. Real power systems offer no shortage of challenging variables for relay algorithms: line length, source strength, power flow, fault location, fault type, R_F, and relay settings.

In general, fault-selection logic is only present to prevent an incorrect operation. That is, fault-selection logic does not produce a trip decision; it only supervises the operation of certain elements (e.g., a phase-to-phase fault selection prevents a phase-to-ground distance element from overreaching for a phase-to-phase-to-ground fault).

A. Relay Fault Selection at the Time of the Event

The 1980s-era microprocessor relay utilized throughout the system in Fig. 1 uses positive-sequence memory voltage polarized mho distance elements for three-zone phase and ground distance protection [2]. The microprocessor implementation allowed for longer memory than traditional relays (about 10 cycles).

This relay introduced a new method (at the time) for faulted phase identification. It was not possible to evaluate the torque for all six distance elements (AB, BC, CA, AG, BG, and CG) in all three zones every quarter-cycle processing interval in an 8-bit microcontroller. Instead, the computer calculates the six Zone 3 torque products and tests their signs.

Each element's torque is the result of (1), substituting the appropriate voltages and currents from Table I.

$$T = \mathrm{Re}\left[\left(Z_r \bullet I - V\right) \bullet VP^*\right] \tag{1}$$

Table I shows the voltage and current combinations used to calculate the torque of each distance element.

TABLE I
VOLTAGES AND CURRENTS USED IN (1)

Element	Voltage (V)	Current (I)	Polarization (VP)	Torque (T)
AG	VA	IA + K • IR	VAlm	Tag
BG	VB	IB + K • IR	VBlm	Tbg
CG	VC	IC + K • IR	VClm	Tcg
AB	VA – VB	IA – IB	–j • VClm	Tab
BC	VB – VC	IB – IC	–j • VAlm	Tbc
CA	VC – VA	IC – IA	–j • VBlm	Tca

m: denotes memory voltage
K = 1/3 (ZO/ZL – 1) . . . residual current compensation factor

Positive products indicate impedances inside the expanded mho circle characteristics. A larger number indicates stronger torque, or a fault nearer the origin [3].

With respect to an overreaching element such as Zone 3, comparing torque was a useful and computationally efficient fault type discriminant. In other words, every quarter cycle, the Zone 3 mho elements update and present their operate/restraint state and torque value to a fault identification (lookup) table. Essentially, with a few qualifiers, the loop (AB, BC, CA, AG, BG, and CG) that has the highest positive torque product is declared the fault type [4]. Once the fault type is selected, corresponding impedance elements are allowed to operate.

Early technical literature identifies a weakness with selectivity in this scheme. Zone 1 must not operate for a fault beyond the remote bus. A double line-to-ground fault with R_F tends to cause the ground element associated with the leading phase to overreach for certain values of R_F. The relay scheme must, therefore, correctly block the ground distance elements for these faults.

The success of determining fault type by comparing Zone 3 element torques is dependent on the reach setting and R_F. To illustrate this, the system in Fig. 1 was modeled. A BCG fault was placed near Substation A. Torque products for the BC and BG Zone 3 elements in Relay Z were calculated for several values of R_F and Zone 3 reach using the Mathcad® worksheet shown in Appendix A. Fault impedance was varied from 0 to 4 ohms. Several values of Zone 3 reach were evaluated: 155%, 310%, and 620% of the protected Line C-D impedance. The results of this exercise are shown in Fig. 7.

Several interesting observations can be made from Fig. 7. With a Zone 3 reach setting at 155% of Line C-D, the relay will incorrectly identify the fault type as BG for R_F up to 3 ohms. Increasing the Zone 3 reach setting to 310% allows for correct BC fault type selection near 1 ohm R_F and for R_F values of about 1.5 ohms and above. However, for R_F values near 1 ohm, the relay incorrectly identifies the fault type as BG. Increasing the Zone 3 reach setting to 620% ensures that the relay makes the correct BC fault type selection for all values of R_F.

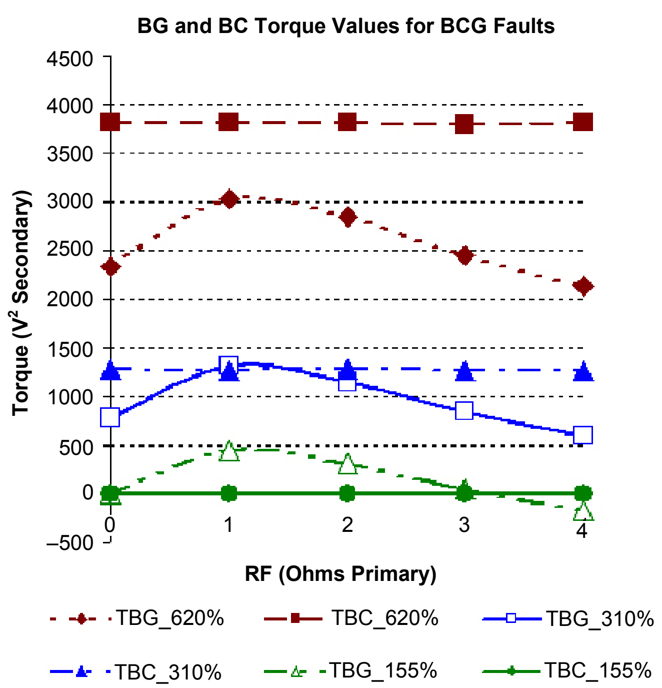

Fig. 7. BG and BC Torque Values for Different R_F and Zone 3 Reach

The conclusion drawn from Fig. 7 is that larger Zone 3 reach settings provide more reliable fault type selection when using torque comparison. Several applications may complicate the user's ability to implement the Zone 3 reach in this manner. If the relay is used in a short-line (or a series of short lines) application as in Fig. 1, reach settings may be set small. Also, if Zone 3 is relied upon to provide backup protection for complete failures at the remote station, such as a dc battery failure, it will be set to trip and must coordinate with remote relays. Short-line applications with Zone 3 used as backup, therefore, conspire against the recommended practice of setting Zone 3 larger to ensure proper fault type selection. With this relay, the engineer must model the power system, perform fault studies, and examine fault type selection based on Zone 3 torques to ensure the applied settings are secure.

B. Fault Selection Today

In 1993, a distance relay design introduced several innovations that are still state-of-the-art at the writing of this paper (2008) [5]. These innovations include:

- A computationally efficient numerical method of characterizing distance elements onto a single point on a number line. This allows all six impedance loops (AB, BC, CA, AG, BG, and CG) for multiple zones (e.g., four zones of distance element protection) to be calculated, measured, and compared every processing interval (e.g., every 1/8 cycle) [6].
- Positive-sequence memory polarization that allows distance elements to retain directional security for close-in, low- (or zero-) voltage faults for over one second. This is particularly important for the application of distance elements on short lines.
- Fault identification selection (FIDS) logic that uses measured negative- (IA2) and zero-sequence (IA0) currents. This method is *not* settings-dependent and addresses two major concerns: 1) that ground distance elements do not overreach for line-to-line-to-ground (LLG) faults, and 2) that phase distance elements do not operate for close-in, line-to-ground (LG) faults [7].

The FIDS logic in the modern design compares the angle between IA0 and IA2 (referenced to A-phase). Fig. 8 shows that IA0 and IA2 are in phase for AG and BCG faults without R_F.

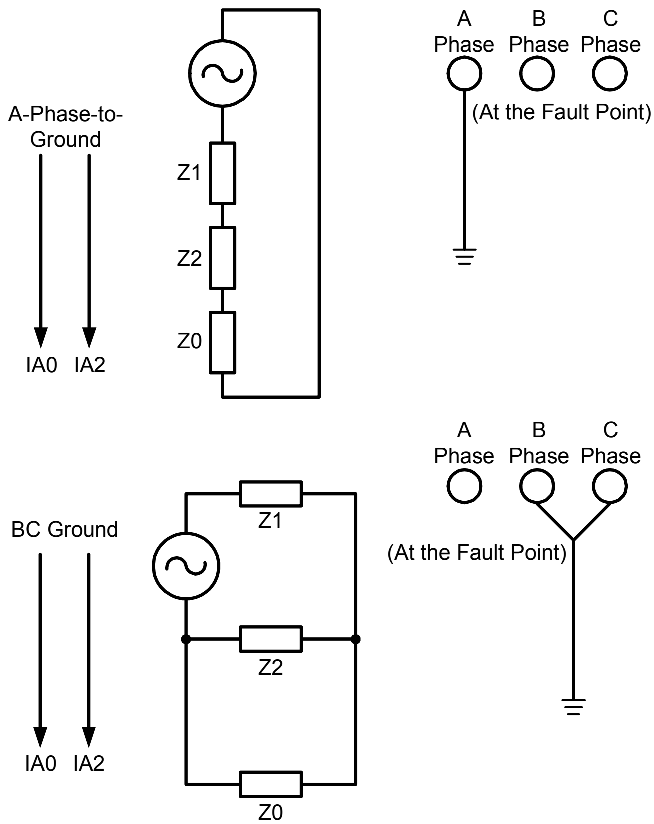

Fig. 8. IA0 and IA2 Relationship for AG and BCG Faults (Without R_F)

Fig. 9 shows the IA0 and IA2 relationships for AG, BG, and CG faults. Note that IA2 lags IA0 for a BG fault, but IA2 leads IA0 for CG faults. Thus by creating "sectors," we can use these relationships to determine fault type.

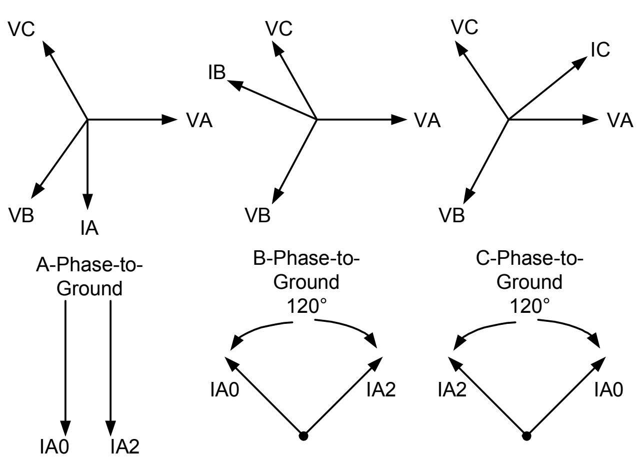

Fig. 9. IA0 and IA2 Relationship for AG, BG, and CG Faults

As we add R_F, these angles increase. For a system with the source and line impedances shown in the legend in Fig. 10, as R_F increases, IA2 lags IA0 by an increasing angle. When the angle is more than 30 degrees from its expected value, we can compare the phase and ground R_F estimates and select the fault type from the minimum resistance. For example, if we refer to Fig. 10, a comparison of Rag against Rbc would reveal that Rag is much larger than Rbc. Therefore, the logic selects BC (over AG) as the fault type.

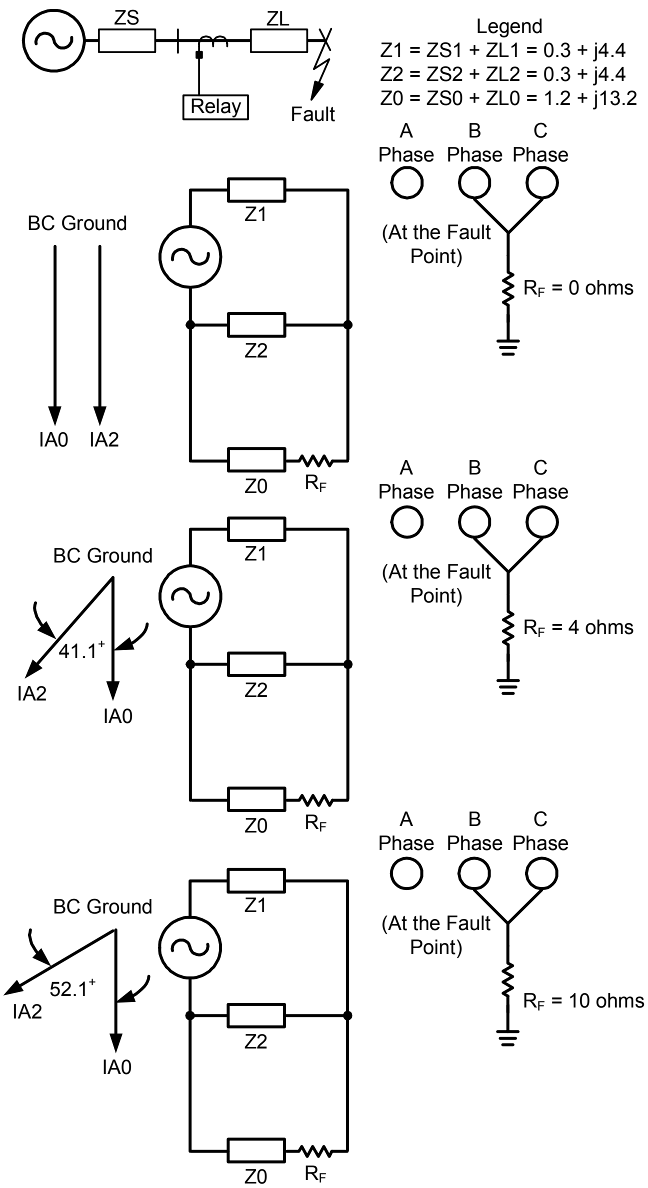

Fig. 10. Effects of Increasing R_F for a BCG Fault

Table II summarizes the modern design FIDS logic.

TABLE II
FIDS LOGIC IN MODERN DESIGN

Angle Between IA2 and IA0	Fault Type Permission
IA2 is ± 30 degrees of IA0	Permit AG or BC. Select A-phase or B-C-phase based on the lowest mho element calculated reach.
IA2 lags IA0 by 90 to 150 degrees	Permit BG or CA. Select B-phase or C-A-phase based on the lowest mho element calculated reach.
IA2 leads IA0 by 90 to 150 degrees	Permit CG or AB. Select C-phase or A-B-phase based on the lowest mho element calculated reach.
IA2 leads or lags IA0 by 30 to 60 degrees	Select the phase-to-phase mho element with the lowest calculated reach. Compare Rag with the R_F of that element. If Rag is lower, the fault involves A-phase. If not, select phase-to-phase element.
IA2 lags IA0 by 60 to 90 degrees or 150 to 180 degrees	Select the phase-to-phase mho element with the lowest calculated reach. Compare Rbg with the R_F of that element. If Rbg is lower, the fault involves B-phase. If not, select phase-to-phase element.
IA2 leads IA0 by 60 to 90 degrees or 150 to 180 degrees	Select the phase-to-phase mho element with the lowest calculated reach. Compare Rcg with the R_F of that element. If Rcg is lower, the fault involves C-phase. If not, select phase-to-phase element.

C. How Would the Modern Design Select the Fault Type for the August 1999 Event?

Fig. 11 shows the relationship between IA0 and IA2 from the actual Relay Z fault data. IA2 lags IA0 by 49 degrees. The relay selects the phase-to-phase element with the lowest calculated reach (Mbc) and compares Rag with that resistance (Rbc). Because Rbc is the lowest (Rag is actually ignored in this case because it is a negative value), the FIDS logic selects BC.

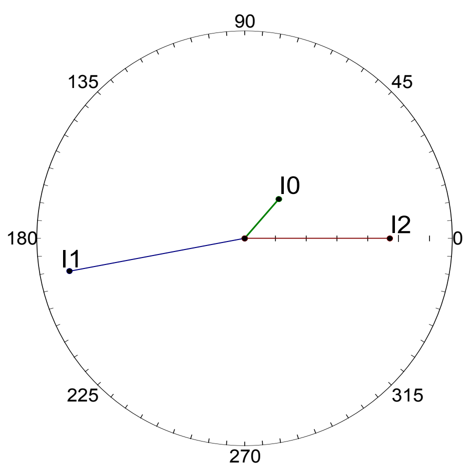

Fig. 11. Event Data from Relay Z During the Fault at Cycle 7

TABLE III
MODERN DESIGN MHO REACH AND R_F CALCULATIONS FROM SUBSTATION D DATA DURING THE FAULT AT CYCLE 7

Fault Identification Angle: ang (Ia0) – ang (Ia2) = 48.88 degrees			
Mho Reach		**Fault Resistance**	
Mag = –12	Mab = 4.44	Rag = –1.46	Rab = 14.25
Mbg = 0.2	**Mbc = 0.44**	Rbg = 1.18	**Rbc = 0.28**
Mcg = 1.44	Mca = 7.5	Rcg = 0.19	Rca = –11.9

IV. FINDING ROOT CAUSE

A. Analysis of the Original Fault and Short-Term Solutions

For the original fault, the first step in determining root cause is to ask what was expected to happen? For a BCG fault near Bus A, we expected the nearest terminals (breakers for Relays U and V) to open and to experience no other operations.

What actually happened? Operation logs from the utility and inspection of the event reports showed that the two terminals closest to the fault did in fact operate, but in addition, two relays overreached (Relays X and Z) and were tripped by Zone 1 BG elements.

We analyzed the event data from the relays that overreached using worksheets similar to Appendix A. In both cases, we observed that the Tbg torque product produces the highest positive value. Thus the relays select BG as the fault type. This confirms that the relays operated as designed and as set (albeit with an undesired outcome) for this out-of-section fault.

Using this same worksheet, we wanted to show some immediate steps that could be taken by the utility to prevent this and other occurrences. For example, we showed that reducing the Zone 1 reach from the as-set value of 75% to 53% of the line impedance would have prevented operation (Tbg for Zone 1 becomes negative). We also showed that increasing Zone 3 to about 500% of the line impedance would have caused the fault-selection logic to perform correctly (Tbc would produce the highest positive value), and again, prevent this operation.

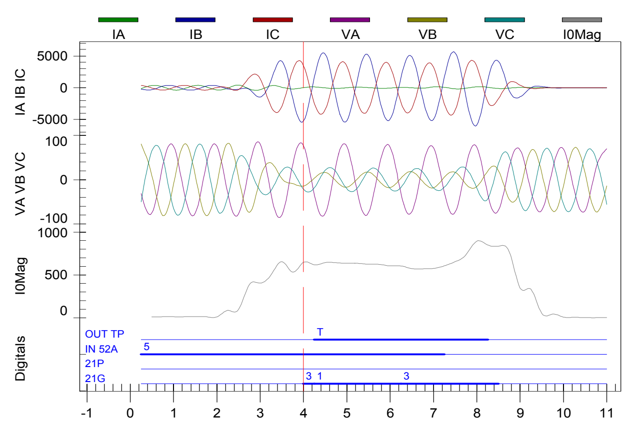

Fig. 12. Event Data from Relay Z Shows Zone 1 BG Overreach

Mho Distance Calculations:

$Re(Tag) = -4.708 \times 10^3$	$Re(Tbg) = -1.318$	$Re(Tcg) = -1.407 \times 10^3$
$Re(Tab) = -4.555 \times 10^3$	$Re(Tbc) = -802.475$	$Re(Tca) = -5.236 \times 10^3$

$r \equiv 0.53$

Mho Distance Calculations:

$Re(Tag) = -5.115 \times 10^3$	$Re(Tbg) = 2.192 \times 10^3$	$Re(Tcg) = -210.06$
$Re(Tab) = -3.126 \times 10^3$	$Re(Tbc) = 2.273 \times 10^3$	$Re(Tca) = -4.573 \times 10^3$

$r \equiv 5.00$

Fig. 13. Short-Term Settings Solutions Where r Is the Reach Setting

Reducing Zone 1 or extending Zone 3 reach settings were options that would need to be evaluated by the utility. For example, if Zone 3 is used as a remote backup (remote breaker failure or battery failure), extending Zone 3 reach may not be practical.

In short lines (where Z1L is less than ½ ohm secondary), Zone 1 reach must often be reduced for a myriad of reasons. These difficulties include:

- Voltages and currents at the relay for close-in and remote bus faults appear nearly identical on short lines.
- CVT transients are exacerbated by SIRs (source impedance ratios) greater than four.
- Low voltages at the relay (less than 5 V secondary) for three-phase faults require additional directional element security.
- Directional elements must be sensitive enough to see low-voltage faults but not operate for system unbalances.
- PT accuracy errors increase greatly at low voltages (less than 5 V secondary).
- Fixed relay accuracy errors (as well as modeling errors) play a larger factor in short reach applications.

Careful system analysis must determine if Zone 1 can be applied on a short line, and if so, at what reduced reach and possible time delay. In some applications, Zone 1 may have to be disabled altogether.

Today, short lines often afford inexpensive and reliable communications options (e.g., radio, fiber, etc.) for dual primary communications-assisted tripping schemes or line current differential systems to provide instantaneous tripping for faults on the entire line without requiring Zone 1. Even still, this discussion highlights the effort required by the user in determining secure settings.

B. Replay of Original Fault Data Using COMTRADE Into 1980s-Era Microprocessor Relay

To further validate our Mathcad model and theory, the event report data recorded by Relay Z during the 1999 BCG fault was converted to COMTRADE files and replayed into a relay in the lab. The relay was the same model, the 1980s-era microprocessor relay described earlier.

In the first test, Zone 1 was set to 75%, and Zone 3 was set to 155% of the Line C-D impedance. These settings match those installed in Relay Z during the fault. The relay Zone 3 BG element sees the fault and determines the fault to be a BG-fault type. Once enabled incorrectly by the fault-selection logic, the Zone 1 BG element operates and overreaches. The results of this test are shown in Fig. 14. This test simply confirmed the operation of the relay in the field and our ability to duplicate its operation in the lab.

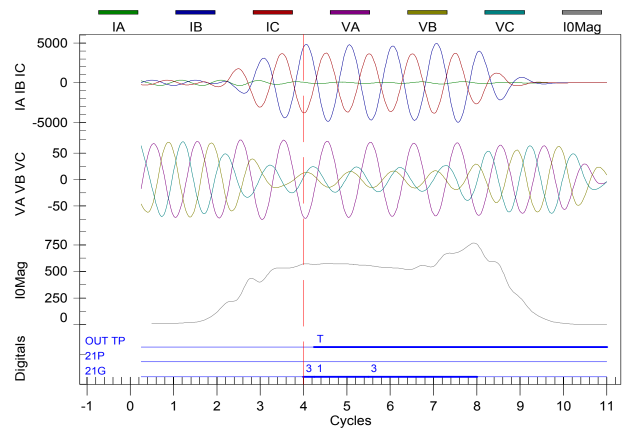

Fig. 14. Zone 1 at 75%, Zone 3 at 155% as Set—Replay Shows Trip

In the second test, Zone 1 reach was left at 75%, and the Zone 3 reach was increased to 310%. Both BC and BG Zone 3 elements see the fault. The simulation was run 12 times. Two times out of 12, the relay incorrectly determined the fault to be BG and enabled a Zone 1 BG element overreach. Ten times out of 12, the relay restrained; for these, the relay determined the fault to be BC and enabled the BC distance elements, which correctly identified the fault location to be just beyond the Zone 3 reach. The results of this test are shown in Fig. 15.

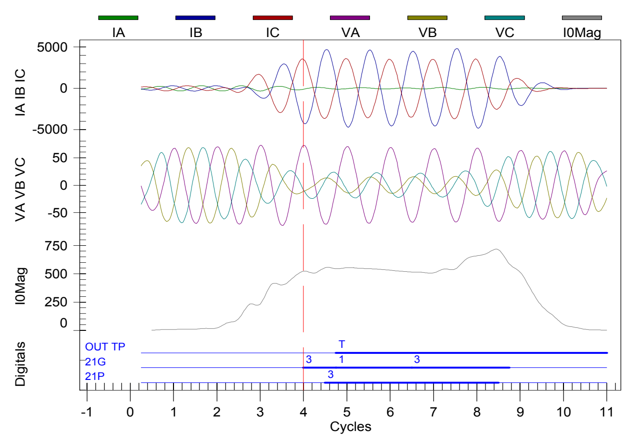

Fig. 15. Replay With Zone 1 Set to 75%, Zone 3 at 310%—Trip

Recall from Fig. 7 that there exists a small region of R_F at around 1 ohm where, even at a Zone 3 reach setting of 310%, the relay would incorrectly determine a BG fault type. Using the event data from Relays U and Z, the actual system source impedances at the time of the fault, R_F and fault location were determined. Source impedances during the fault were different from those used in fault studies and system modeling by the utility. *Interestingly, the calculated R_F during the fault was 0.92 ohms.*

In the third test, Zone 1 was set to 75%, and the Zone 3 reach was increased further to 620%. At this reach, the relay now securely determines the fault type as BC for every simulation. This enabled the BC distance elements, which correctly identified the fault location to be just beyond the Zone 3 reach. The results of this test are shown in Fig. 16.

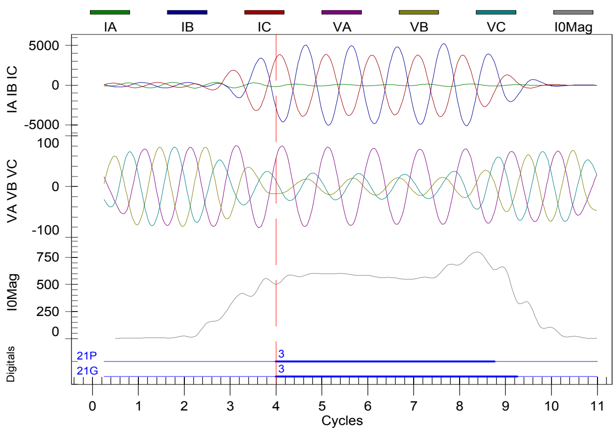

Fig. 16. Replay With Zone 1 at 75% and Zone 3 at 620%—No Trip

In the fourth test, the Zone 3 element reach was restored to its original 155% value. Because this was a short-line application, a common necessity for securing the Zone 1 elements against overreach is reducing Zone 1 reach. Fig. 17 shows that by further reducing the Zone 1 reach to 53% of the line, the overreach is prevented for this particular fault.

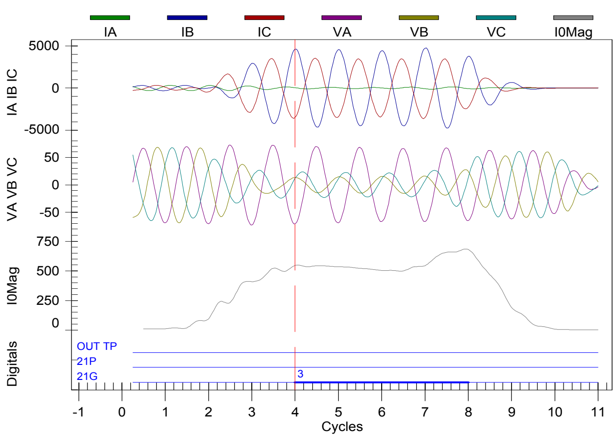

Fig. 17. Zone 1 at 53%, Zone 3 at 155%—No Trip

Replaying actual event data through a so-called exemplar relay in the lab is an excellent method of validating field performance and performance with different settings. It allowed us to confirm some conclusions made through Mathcad analysis—that Zone 1 reach reduction and/or Zone 3 reach extension would be the two easiest means to prevent overreach for this particular fault.

C. Mathcad Simulation of State-of-the-Art Microprocessor Relay

To prove that the 1993 (and today's) relay would have been secure, its response to the event report data recorded by Relay Z during the 1999 BCG fault was simulated using Mathcad. This testing confirms the reliable performance of the improved FIDS logic. It also proves that the newer relay is not dependent on user settings for fault type selection security.

The modern relay is set with the original Zone 1 reach at 75% and Zone 3 reach at 155% of the protected line impedance. Directional element thresholds are set based on the positive-sequence line impedance.

In Fig. 18, the Mathcad worksheet plots the 49-degree angle by which IA2 lags IA0. Given this, the relay selects the phase-to-phase mho element with the lowest calculated reach (BC in this case).

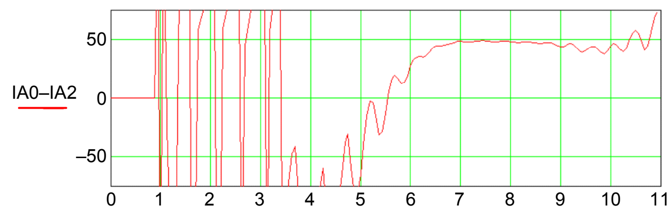

Fig18. IA2 Lags IA0 by 49 Degrees (Matches Original Event Data)

Then it compares Rag with the R_F of Rbc. If Rag is lower, the fault involves A-phase. If not, the relay selects the phase-to-phase element (BC). This decision process is shown in Fig. 19 by the outcome of the asserted FSA-60.

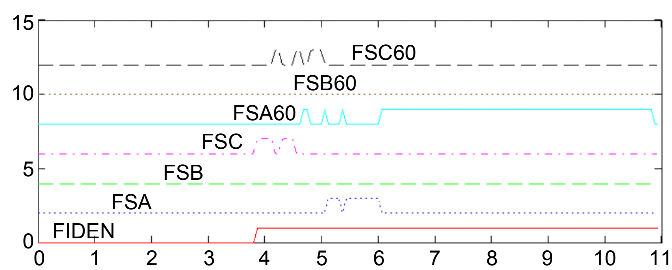

Fig 19. FIDS Response of 1993-Era Relay to Event Data

In Fig. 20, we can see that the 1993-era, Zone 1 MBG element sees the fault within its reach. This plot shows the response of the reach calculation only and includes none of the supervision logic. In fact, even though this element sees the fault, it is blocked from operation by the FIDS logic, unlike the 1980s-era relay.

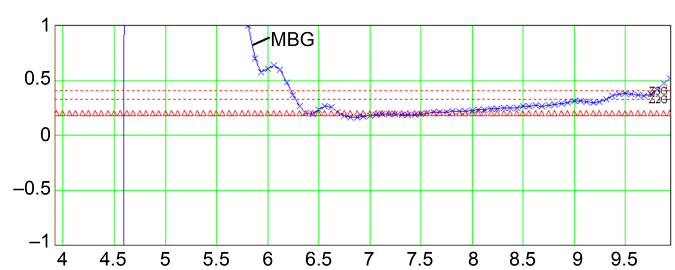

Fig. 20. MBG Distance Element Response in Mathcad Simulation of Event Data (This Element Is Blocked by FIDS Logic for This Fault)

Fig. 21 shows the logic that supervises the MBG element [8]. In order to allow the operation of the Zone 1 MBG element, the relay would have to enable the FSB element. For this fault, FSB remains deasserted due to improved FIDS logic.

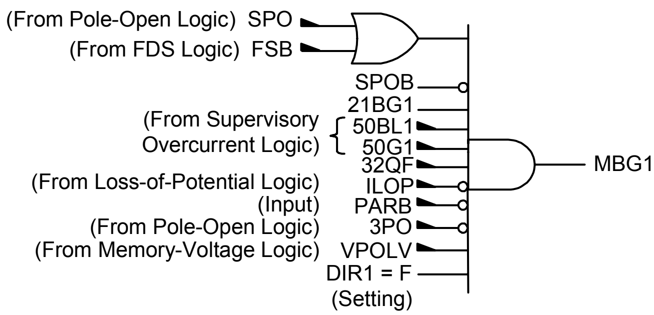

Fig 21. Zone 1 Mho Ground Distance Element Logic

Because the relay now enables the MBC elements, these are allowed to operate if the fault is seen within their reach. Fig. 22 shows the Zone 1, 2, and 3 MBC element response to the fault data. The fault location is determined accurately—just beyond the Zone 3 reach. The relay would not have operated for this fault. Fig. 23 shows the logic that supervises the MBC element.

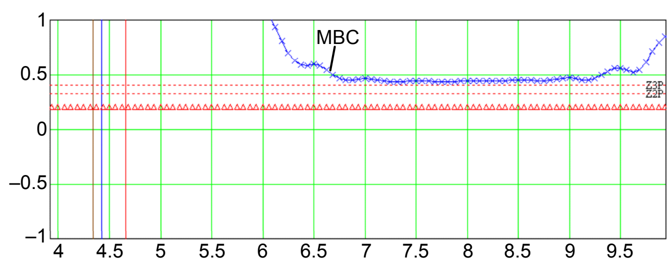

Fig 22. MBCx (Where x Is Zone 1, 2, 3) Distance Element Response to Event Replay. No Operation. MBCx Would Be Allowed to Operate Per FIDs, but Fault Is Just Beyond MBC3

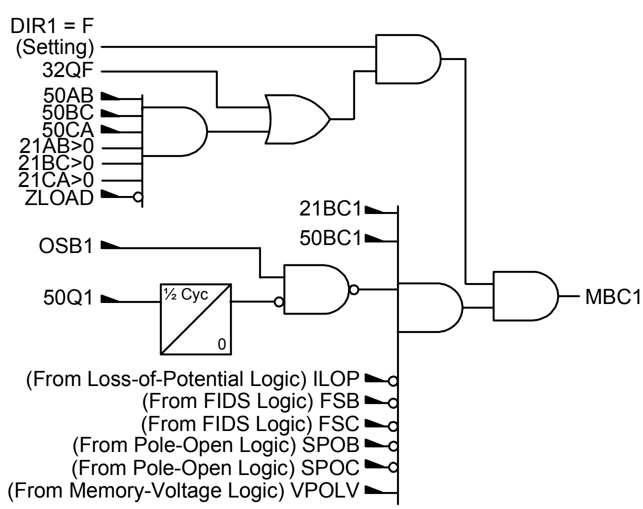

Fig 23. Zone 1 Mho Phase Distance Element Logic

D. Replay of Original Fault Data Using COMTRADE Into State-of-the-Art Microprocessor Relay

To further validate our Mathcad model and theory, the event report data recorded by Relay Z during the 1999 BCG fault were converted to COMTRADE files and replayed into a relay in the lab. The relay was a 1993-era microprocessor relay, as described earlier.

The modern relay is set with the original Zone 1 reach at 75% and Zone 3 reach at 155% of the protected line impedance. Fig. 24 shows the relay response to the replayed fault data. As the Mathcad simulations predicted, the relay's improved FIDS logic identifies this first as either an AG or BC fault (FSA asserted). The fact that the Z1G element is shown deasserted, despite the fault being within its reach, proves that the FIDS logic determined definitely that this was a BC fault. Further, the data show that the relay determined the fault direction as forward (32QF) and did not operate by any element.

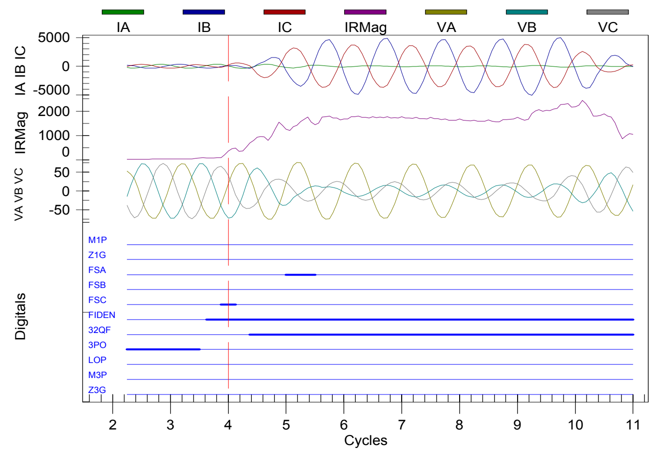

Fig. 24. Replay of Relay Z Event Data Through 1993-Era Distance Relays With Improved FIDS Logic

In summary, the modern relay, with identical settings as in the 1980s-era relay, would be secure.

V. Litigation

Within a few days of the original fault, on August 31, 1999, the utility and manufacturer had exchanged operational data and analyzed the event reports. The likely root cause of the event was theorized and confirmed within a few more days. Plans for improving the security on these lines and other similar applications were underway within several weeks of the original event.

Around the time of the event, the utility and the petrochemical plant were in the middle of a contractual rate dispute that involved lower electric rate offerings based on larger power consumption promised by the plant. The larger consumption never materialized, and the plant was in a position to pay higher rates to the utility in order to pay back some of the savings from the price breaks.

Also, around the time of the event (in May 1999), the manufacturer introduced a service bulletin on the product that operated for the original event. A service bulletin is a notification to affected customers when a known problem or defect is discovered as a way to proactively deal with the problem. This particular service bulletin acknowledged a polypropylene capacitor drift issue that relays of this vintage experienced. The capacitor drift could cause input voltages and currents to the relay to measure out of stated accuracy tolerance. Customers, including this utility, were contacted, and corrective actions were offered to repair or replace relays affected by this service bulletin. The service bulletin specifically included the serial numbers of the relays that operated for the 1999 fault.

Already involved in contentious litigation with the utility, the petrochemical plant filed a legal action in February 2000. In this petition, the plaintiff alleged, among other things, negligence and gross negligence by the utility and the manufacturer for the line misoperations.

Perhaps looking for a convenient "smoking gun," the plaintiffs (attorney and expert witness for the plant) alleged that the relay misoperations were caused by the capacitor drift problem described in the service bulletin. They also alleged product liability by the manufacturer for not notifying the petrochemical plant of this service bulletin and that the relay is "unreasonably dangerous in design, construction, and composition."

The suit alleged that the manufacturer was liable for property damages, loss of production, and lost business revenue and profits. This suit spawned a journey of legal proceedings that stretched over almost eight years and finally reached a confidential settlement in mid-2007.

A. Investigation and Responses to the Allegations

The original customer on record with the manufacturer was notified via the service bulletin, and was the utility in this case. At some point between 1989, when the relays were originally purchased from the manufacturer, and 1999, the ownership of substation equipment had transferred from the utility to the petrochemical plant, with no notification given to the manufacturer. It is reasonable to assume that confusion over the true ownership of several relays did delay delivery of the service bulletin to the petrochemical plant. But, it is unlikely that the petrochemical plant would have had time to repair or replace several relays between May and August 1999, even if the service bulletin had been delivered in May. This discussion highlights the necessity for manufacturers to keep accurate records of product ownership, the role that users have in this process, and the need for timely, documented notification of product problems.

Although the root cause had already been determined by a thorough analysis by the utility and manufacturer, that same honest and detailed correspondence between the utility and manufacturer became weapons for the plaintiff during discovery. Both the utility and manufacturer were put in a position of defending the root-cause findings and proving that capacitor drift *was not* the root cause.

During our investigation, we knew capacitor drift could cause inaccuracies in the measured voltages and currents, but believed it was highly unlikely (or impossible) that it could cause a misoperation of this type. Still, we took a methodical approach to investigate it.

B. Original Event Analysis Shows Capacitor Drift

Fig. 25 shows the current magnitude plot from all three relays (V, X, and Z) that saw the same fault from the same source. We would expect the currents to be the same. As it turns out, the B-phase current on Relay X was low (by about 23%). We also observed that the angle was off by about 12 degrees lagging.

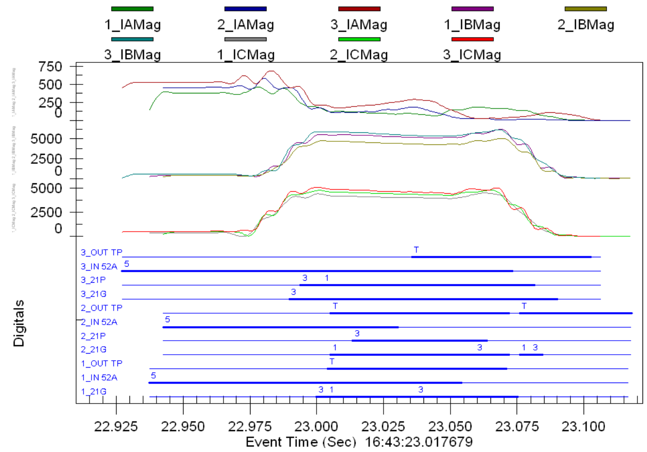

Fig. 25. Screen Capture of Current Magnitudes From All Three Relays Shows Low B-Phase on Relay X. 1 = Relay V, 2 = Relay X, 3 = Relay Z

At the plaintiff's request, several different tests were performed between 1999 and 2001 that showed that the B-phase current on Relay X measured lower than its specified tolerance. Although much effort was taken for these tests, it just confirms what we already knew from the event data.

Moreover, if only one relay (Relay X) was experiencing drift at the time of the event, how would one explain the overreach operation on the other relay (Relay Z) not experiencing drift on the day of the fault?

Also at the plaintiff's request, a test of Relay Z was performed in 2005. During this test, nearly 5 ½ years after the fault, the relay's C-phase current was found to have drifted by 10% in magnitude. From Table I, we know that the C-phase current is used only indirectly (as a component of 3I0) by the relay in the BG element calculation. Given that we have the actual data from the event in 1999, what good does it do to know the relay has experienced some drift since then, most of the time having been spent on an inventory room shelf? The important question is, did capacitor drift affect the relay operation?

C. Mathematical Analysis and Lab Testing Show That Measurement Errors From Capacitor Drift Did Not Cause Misoperations

Intuitively, a lower current magnitude, if anything, would make a mho element underreach, not overreach. Still, we performed analysis, both mathematically and through replaying the event data through the original relays and the exemplar relay, to discover the result.

First, we used the original event data in a mathematical model of the elements in Relay X, using the same analysis tool shown in Appendix A. We increased the magnitude of the B-phase current by 23% and adjusted the angle by 12 degrees to calculate how the relay would have performed had there been no capacitor drift. Table IV shows the mho element torque products for the original fault (with drift), as well as the performance with a higher B-phase current (without drift). In this table, the higher positive value is selected as the fault type.

TABLE IV
RELAY TORQUES FROM ORIGINAL EVENT AND ADJUSTED TO SIMULATE NO CAPACITOR DRIFT

Data Used	Tbg (BG torque)	Tbc (BC torque)
Original With Drift	+410	+37
Compensated IB	+509	+113

Notice that with capacitor drift, the Tbg torque is less than without drift (e.g., if the apparent impedance plots further from the origin, the element is less likely to operate). As suspected, capacitor drift tended to make the element underreach, not overreach.

In both cases, the Tbg torque is decisively higher than Tbc. This means that, *even with no capacitor drift, the relay would have selected BG as the fault type*. In other words, capacitor drift made no difference in the relay operations.

Testing was also performed using the relays at Substations C and D and the exemplar relay. The fault quantities were replayed through the relays, adjusting for the capacitor drift. In all cases, the relays still produced a trip. Again, this proved that the capacitor drift made no difference in the relay misoperations.

D. Plaintiff's Strategy: Never Let the Truth Get in the Way of a Good Story

Regardless of sound data that showed otherwise, the plaintiffs continued to hammer away on the capacitor drift issue. Perhaps the only explanation we can guess is that, in general, people (regardless of profession) deal with what they can understand. The plaintiffs most likely believed that it would be easier for them to convince a jury that a "negligent" manufacturer's defect caused a problem than it would be for the defense to explain the nuances of fault identification selection logic and the evolution of that technology over time.

The plaintiffs alleged a faulty, grossly negligent design. However, in the 1980s, this was the state-of-the-art. Indeed, improving the performance of FIDS algorithms, especially with regard to preventing the overreach of Zone 1 phase-to-ground elements for phase-to-phase faults with R_F, has been a research priority and the focus of technical literature for many individuals and manufacturers that continues to this day [9].

Consider seat belt technology. Let's say you buy a restored 1969 Camaro. It has a lap seat belt. If you get into a wreck, would you sue Chevrolet because the restraint and safety system was negligent, flawed, or faulty? After all, this vehicle includes no shoulder restraint, no advanced frame crumple zones, no front and side curtain air bags, etc. There is a state-of-the-art in any industry. Relays designed in the 1980s had 1980s technology, with its benefits and weaknesses in design. Advancements continue every day, as the 1993-era relay improvements prove.

VI. CONCLUSIONS

It is hard to find too much fault on the part of the utility. Determining relay settings has always been considered an art and science. It is likely that the importance of the Zone 3 reach setting in fault type selection and security was not completely understood. Given the short-line application, with the relay and communications options available at the time, the Zone 1 and Zone 3 settings are understandable. And, determining secure settings for a given fault is always a much easier task to perform after the fault, given the benefit of hindsight and data.

Obviously, they had from 1993 to 1999 to become aware of the new technology, which was documented in widely publicized technical literature. They had from 1993 to 1999 to replace and upgrade the relays to better and more secure products. Why didn't they? It is possible that they were not aware of all of the issues involved, but it was more likely economics. After all, there are thousands of traditional relays still in service today, despite their known weaknesses in performance and reliability. Nevertheless, it does show the responsibilities of the manufacturer to communicate new technology and of the user (both the utility and petrochemical plant) to stay current with technology.

What might the petrochemical plant have done differently? The application and settings should have been reviewed after they took ownership of the substations. Setting changes or the installation of newer technologies might very well have been the outcome of this process. The change in ownership of products should have been reported to the manufacturer. This would have ensured more timely notification of service bulletins. When the event occurred, they should have worked more cooperatively to discover the root cause of the outage and implement solutions. Contentious litigation based on an invalid premise is a poor substitute for any number of positive alternatives. Finally, the guaranteed 100% availability of power is not possible, even with the latest technology installed on the existing system. But, if a two-minute outage is deemed unacceptable, they should invest in additional lines, substations, or on-site generation to supply power to their critical loads.

This case can be considered a lesson learned for *all* engineers. Don't be the engineer who has "one year of experience ten times." Stay current on the development of new technology. Work hard to always learn, re-evaluate how you do things, and review relay applications and settings. Our shared goal is to make electric power safer, more reliable, and more economical over time.

It is interesting to ponder a remark made by an attorney during the litigation. The attorney said of the manufacturer's free technical support and honest dealings that "you'll learn." It is indeed a dark outlook on our industry's future if this holds true. Can you imagine a day when engineers don't work together to solve problems for fear of litigation?

Thankfully, not every two-minute outage ends up in eight years of litigation. Said a different way, this petrochemical plant experienced 99.99962% availability with their electric power provider in 1999. This is not to minimize responsibility in any way—electric power is critical to every facet of our economy and standard of living. However, if every blink or outage led to litigation, the cost of electric power might be 100 times higher than what it is today.

Through root-cause investigation, the following conclusions were made:

- In August 1999, a lightning strike caused a BCG fault on a 138 kV line. Two adjacent lines tripped, causing a two-minute outage to a petrochemical plant.
- Engineers from the utility and manufacturer cooperatively worked to find root cause. Event analysis showed that root cause was the fault-selection logic and was related to Zone 3 reach settings in a 1980s vintage microprocessor distance relay. Setting changes could be made to improve security and reduce the risk of future occurrences.
- Superior FIDS logic using the relationship between negative- and zero-sequence current had been developed in a newer 1993 design that is still state-of-the-art today. This logic was available in a different relay design and could provide the best solution, without the need for reach settings changes.
- The petrochemical plant, already involved in a separate legal action against the utility, sued the utility and relay manufacturer for a number of items, including negligence and product liability.
- Around the time of the fault, the manufacturer had issued a service bulletin on the relays involved in the misoperations.
- The plaintiffs alleged that the root cause was capacitor drift, as described in the service bulletin.
- The manufacturer and utility independently and co-operatively, through analysis and testing, determined that the plaintiff's allegations were false, with convincing mathematical and empirical data.
- Despite this, the legal action continued for nearly eight years, eventually resulting in a confidential settlement.
- Engineers should work hard to stay current with state-of-the-art developments.

Finally, we believe that, regardless of the legal system and the possible outcomes, engineers should always strive to find and never be afraid of determining the root cause of a problem.

The authors are proud and grateful to be part of a great profession—engineering.

VII. Appendix

December 17, 2007 – Fault Near A, Relay Z Response
Distance Element Calculation Sheet

$a \equiv -0.5 + i \bullet 0.866$ $\quad$ $rad \equiv 1$ $\quad$ $deg \equiv \pi/180 \bullet rad$ $\quad$ $I \equiv 1 .. 43$

Line parameters from relay settings:

$PTR \equiv 1200$ $\quad$ $CTR \equiv 240$ $\quad$ $MTA := 82\ deg$ $\quad$ $LL := 2.06$

$Z1L := 1.32 \bullet e^{j \bullet 75.0 \bullet deg}$ $\quad$ $Z0L := 4.34 \bullet e^{j \bullet 71.6 \bullet deg}$

$arg(Z1L) = 75\ deg$ $\quad$ $Z1Lsec := Z1L \bullet CTR/PTR$ $\quad$ $Z0Lsec := Z0L \bullet CTR/PTR$

Prefault primary voltages for polarizing memory – obtain from prefault data in event report or system model:

$Vap1 := 81.6/.001 \bullet e^{(j \bullet 0 \bullet deg)}$ $\quad$ $Vbp1 := 81.6/.001 \bullet e^{(j \bullet 240 \bullet deg)}$ $\quad$ $Vcp1 := 81.6/.001 \bullet e^{(j \bullet 120 \bullet deg)}$

$Vap := Vap1$ $\quad$ $Vbp := Vbp1$ $\quad$ $Vcp := Vcp1$

Enter the primary fault quantities from event report or system model:

$Va := 89.5/.001 \bullet e^{(j \bullet 1.0 \bullet deg)}$ $\quad$ $Ia := 637 \bullet e^{(j \bullet -62 \bullet deg)}$

$Vb := 16.5/.001 \bullet e^{j \bullet 176 \bullet deg}$ $\quad$ $Ib := 6348 \bullet e^{j \bullet 176 \bullet deg}$

$Vc := 26.9/.001 \bullet e^{(j \bullet 119.0 \bullet deg)}$ $\quad$ $Ic := 4970 \bullet e^{(j \bullet 19 \bullet deg)}$

$Ir := Ia + Ib + Ic$

Symmetrical components (for ABC system rotation):

$Va0 := 1/3 \bullet (Va + Vb + Vc)$ $\quad$ $|Va0| = 2.182 \times 10^4$ $\quad$ zero-sequence volts primary

$Va2 := 1/3 \bullet (Va + a^2 \bullet Vb + a \bullet Vc)$ $\quad$ $|Va2| = 2.841 \times 10^4$ $\quad$ negative-sequence volts

$Va1 := 1/3 \bullet (Va + a \bullet Vb + a^2 \bullet Vc)$ $\quad$ $|Va1| = 4.146 \times 10^4$ $\quad$ positive-sequence volts

$Ia0 := 1/3 \bullet (Ia + Ib + Ic)$ $\quad$ $|Ia0| = 668.796$ $\quad$ zero-sequence amperes primary

$Ia1 := 1/3 \bullet (Ia + a \bullet Ib + a^2 \bullet Ic)$ $\quad$ $|Ia1| = 3.783 \times 10^3$ $\quad$ positive-sequence amperes

$Ia2 := 1/3 \bullet (Ia + a^2 \bullet Ib + a \bullet Ic)$ $\quad$ $|Ia2| = 2.654 \times 10^3$ $\quad$ negative-sequence amperes

$arg(Va0) = 23.627\ deg$ $\quad$ $arg(Ia0) = 131.683\ deg$

$arg(Va1) = -6.341\ deg$ $\quad$ $arg(Ia1) = -79.163\ deg$

$arg(Va2) = -5.263\ deg$ $\quad$ $arg(Ia2) = 89.297\ deg$

$k := (Z0L - Z1L)/3 \bullet Z1L$ $\quad$ $|k| = 0.763$ $\quad$ $arg(k) = -4.884\ deg$

$VAP := 1/3 \bullet (Vap/PTR + a \bullet Vbp/PTR + a^2 \bullet Vcp/PTR)$

$|VAP| = 67.999$ $\quad$ $arg(VAP) = 7.278 \times 10^{-4}\ deg$

$VABm := VAP - a^2 \bullet VAP$ $\quad$ $VBCm := a^2 \bullet VAP - (a \bullet VAP)$ $\quad$ $VCAm := a \bullet VAP - VAP$

$LNANG := arg(Z1L)$

$SHIFT := MTA - LNANG$

$ang := exp(j \cdot SHIFT \cdot deg)$ $\quad SHIFT = 7\ deg$

$Vab := Va - Vb \quad Vbc := Vb - Vc \quad Vca := Vc - Va$

$Iab := Ia - Ib \quad Ibc := Ib - Ic \quad Ica := Ic - Ia$

$Tag := [r \cdot Z1Lsec \cdot ang \cdot (Ia/CTR + k \cdot Ir/CTR) - Va/PTR] \cdot \overline{VAP}$

$Tbg := [r \cdot Z1Lsec \cdot ang \cdot (Ib/CTR + k \cdot Ir/CTR) - Vb/PTR] \cdot \overline{(VAP \cdot a^2)}$

$Tcg := [r \cdot Z1Lsec \cdot ang \cdot (Ic/CTR + k \cdot Ir/CTR) - Vc/PTR] \cdot \overline{(VAP \cdot a)}$

$Tab := [r \cdot Z1Lsec \cdot ang \cdot (Iab/CTR) - (Vab/PTR)] \cdot \overline{(-VAP \cdot a \cdot j)}$

$Tbc := [r \cdot Z1Lsec \cdot ang \cdot (Ibc/CTR) - (Vbc/PTR)] \cdot \overline{(-VAP \cdot j)}$

$Tca := [r \cdot Z1Lsec \cdot ang \cdot (Ica/CTR) - (Vca/PTR)] \cdot \overline{(-VAP \cdot a^2 \cdot j)}$

Mho distance calculations:

$Re(Tag) = -5.164 \times 10^3 \quad Re(Tbg) = 452.089 \quad Re(Tcg) = -980.658$

$Re(Tab) = -4.586 \times 10^3 \quad Re(Tbc) = 3.14 \quad Re(Tca) = -5.276 \times 10^3$

$r \equiv 1.55$ $\quad$ r = distance element reach setting in per unit of the line

$Z2S := -Va2/Ia2 \quad Z0S := -Va0/Ia0$

$|Z2S| = 10.704 \quad |Z0S| = 32.633$

$arg(Z2S) = 85.44\ deg$

$arg(Z0S) = 71.944\ deg$

If the mho element torque is positive, the fault is inside the zone.
If the mho element torque is negative, the element is not asserted.
Larger torque in Zone 3 determines fault type selection.

VIII. Acknowledgments

The authors gratefully acknowledge the work of Ed Schweitzer, Joe Mooney, and Jeff Roberts for teaching us about fault selection, distance elements, and relay operation, Normann Fischer for assistance with Mathcad simulations, and George Alexander for assistance with fault-study simulations. Lastly, thanks to Marion Gerhardt and Marty Golden—two good and decent counselors.

IX. References

[1] R. P. Basler (ed), *The Collected Works of Abraham Lincoln*, Vol. II, p. 81.

[2] SEL-121F/-221F Instruction Manual, Schweitzer Engineering Laboratories, Inc., Pullman, WA. Available: http://www.selinc.com/instruction_manual.htm.

[3] E. O. Schweitzer III, "New Developments in Distance Relay Polarization and Fault Type Selection," presented at the 16th Annual Western Protective Relay Conference, Spokane, WA, October 1989. Available: http://www.selinc.com/techpprs.htm.

[4] U.S. Patent 5,140,492 titled "Distance Relay Using a Polarizing Voltage," Aug 18, 1992. Available: http://www.uspto.gov.

[5] E. O. Schweitzer III and J. Roberts, "Distance Relay Element Design," proceedings of the 47th Annual Texas A&M Conference for Protective Relay Engineers, College Station, TX, April 1993. Available: http://www.selinc.com/techpprs.htm.

[6] U.S. Patent 5,325,061 titled "Computationally-efficient Distance Relay for Power Transmission Lines," June 28, 1994. Available: http://www.uspto.gov.

[7] U.S. Patent 5,515,227 titled "Fault identification system for use in protective relays for power transmission lines" May 7 1996. Available: http://www.uspto.gov.

[8] SEL-321 Instruction Manual, Schweitzer Engineering Laboratories, Inc., Pullman, WA. Available: http://www.selinc.com/instruction_manual.htm.

[9] E. Price and T. Einarsson, "The Performance of Faulted Phase Selectors Used in Transmission Line Distance Applications," presented at the 34th Annual Western Protective Relay Conference, Spokane, WA, October 2007.

X. Biographies

David Costello graduated from Texas A&M University in 1991 with a BSEE. He worked as a system protection engineer at Central Power and Light and Central and Southwest Services in Texas and Oklahoma. He has served on the System Protection Task Force for ERCOT. In 1996, David joined Schweitzer Engineering Laboratories, Inc. where he has served as a field application engineer and regional service manager. He presently holds the title of senior application engineer and works in Boerne, Texas. He is a senior member of IEEE and a member of the planning committee for the conference for Protective Relay Engineers at Texas A&M University.

Karl Zimmerman is a senior application engineer with Schweitzer Engineering Laboratories, Inc. in Belleville, Illinois. His work includes providing application support and technical training for protective relays. He is an active member of the IEEE Power System Relaying Committee and was the Chairman of Working Group D-2 on fault locating. Karl received his BSEE degree at the University of Illinois at Urbana-Champaign and has over 20 years of experience in the area of system protection. He is a past speaker at many technical conferences and has authored several papers and application guides on protective relaying.

Previously presented at the 2008 Texas A&M
Conference for Protective Relay Engineers.

20080416 • TP6313-01