

Obtaining a Reliable Polarizing Source for Ground Directional Elements in Multisource, Isolated-Neutral Distribution Systems

Jeff Roberts, Normann Fischer, Bill Fleming, and Robin Jenkins
Schweitzer Engineering Laboratories, Inc.

Alan Taylor
Los Angeles Department of Water and Power

Presented at the
30th Annual Western Protective Relay Conference
Spokane, Washington
October 21–23, 2003

OBTAINING A RELIABLE POLARIZING SOURCE FOR GROUND DIRECTIONAL ELEMENTS IN MULTISOURCE, ISOLATED-NEUTRAL DISTRIBUTION SYSTEMS

Jeff Roberts, Normann Fischer, Bill Fleming,
and Robin Jenkins
Schweitzer Engineering Laboratories
Pullman, WA USA

Alan Taylor
Los Angeles Department of Water and Power
(LADWP)
Los Angeles, CA USA

ABSTRACT

This paper examines the problem of obtaining a reliable polarizing source for ground directional elements in multisource, isolated-neutral systems. First, we review an existing LADWP 4.8 kV distribution feeder application and the basic characteristics of isolated-neutral distribution networks. Next, we introduce the new directional element for determining ground fault direction in ungrounded distribution networks. We then analyze the polarization problem of ground directional elements in multigrounded, isolated-neutral systems such as those in-service within the LADWP service territory. We conclude by describing the scheme we developed for obtaining a reliable polarizing source for these problematic applications.

INTRODUCTION

In the LADWP 4.8 kV power distribution system, the feeders operate ungrounded. Each feeder circuit is fed by delta-connected power transformer secondaries and all loads are connected phase-phase: i.e. there is no intentional ground. For a ground fault on these systems, the only path for ground current to flow is through the distributed line-to-ground capacitance of the surrounding system and of the two remaining non-faulted phases of the faulted circuit. These fault current paths have very high impedance as compared to solidly grounded systems. The result is very low ground fault current magnitudes.

Because ground faults in ungrounded systems do not affect the phase-to-phase voltage triangle, it is then possible to continue operating the system in the faulted condition. Successful operation of these systems requires all apparatus have a phase-to-phase insulation level and that all loads are connected phase-to-phase.

Ground fault detection in early systems was simple zero-sequence overvoltage relays. This method is simple but not very informative as to which feeder circuit has a single-line-ground fault. Determining which circuit is faulted requires operators to systematically transfer energized feeders to another source until the zero-sequence overvoltage condition is eliminated. This process is very labor and time intensive.

Ground overcurrent relays for these systems require high sensitivity because the fault current is very low compared to solidly grounded systems. Most ground-fault detection methods use fundamental-frequency voltage and current components. The varmetric method is a common directional element solution, but its sensitivity is limited to fault resistances no higher than a few kilohms [1], [2]. There are also methods that use the steady-state harmonic content of current and voltage to detect ground faults [3], [4]. Another group of methods detect the fault-generated transient components of voltage and current [5],[6]. These methods have limited sensitivity, because high-resistance faults reduce the level of the steady-state harmonics and damp the transient components of voltage and current.

The majority of the ground fault detection schemes rely upon zero-sequence voltage. Some multisource, isolated-neutral systems have zero-sequence voltage information available only at the substation sources (rather than at the feeders). An example is the LADWP urban distribution system. Obtaining a reliable voltage polarizing source for the feeder ground directional elements is difficult, especially for changing substation configurations. In this paper, we examine this problem and propose an adaptive solution.

LADWP DISTRIBUTION SUBSTATION AND FEEDERS

Figure 1 shows the front entrance to LADWP's Station A. All 4.8 kV equipment is housed within this building. The roman numerals above the front doors are the first indication of the many years of service. It is also interesting to contrast the elegant building style, typical of that era, with the minimalistic trend we see today for many substations.



Figure 1 Early 1900's Front Entrance to Station A

Figure 2 shows the breaker arrangement and instrumentation that are typical for many of the 4.8 kV feeders at LADWP. Each feeder is instrumented with current transformers (cts) on A- and C-Phases only. The lack of a zero-sequence/core-flux summing ct explains the absence of any feeder ground fault protective relays.

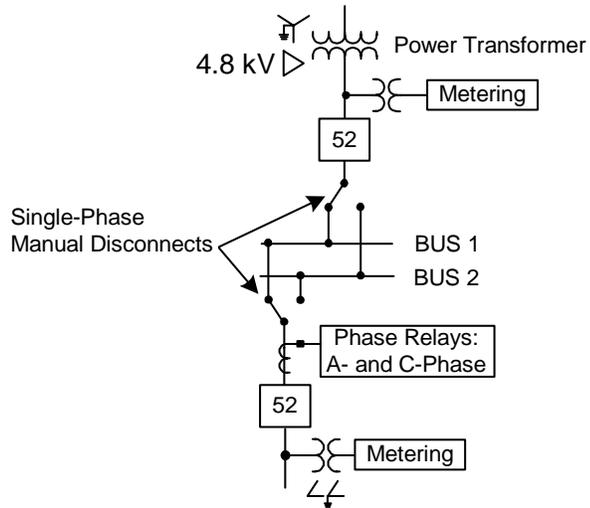


Figure 2 Typical 4.8 kV Feeder Breaker Arrangement and Instrumentation

Figure 3 shows an operator panel used today to control the 4.8 kV bus and distribution feeder system at Station A. Note that the controls and many substation configuration indicators are manual and that the relays and meters are all electromechanical.



Figure 3 Station A Monitoring Panel and Control Console

Earlier in this paper we mentioned the absence of feeder ground fault protective relays. Instead, ground fault incidents are detected by zero-sequence overvoltage relays. When one of these relays detects an overvoltage condition, it causes an alarm. In response to the alarm, the station operator reviews three phase voltage meters that are fed by voltage transformers connected to the power transformer delta winding. The operating procedure is to identify that phase with the lowest voltage magnitude as the faulted phase.

Figure 4 shows one set of meters used for faulted phase indication. Under normal operating conditions, all three phase voltage meter dials should point towards the green markings (the dial

position indication shown in Figure 4 indicates normal). Notice the red region marked on each meter. If the meters read in this region, the system is in a ferroresonance condition.



Figure 4 Existing Ground Fault Detection System Consists of Phase Voltage Meters

Figure 5 shows the existing manually operated disconnect switches. When operators detect a ground fault, they then manually reconfigure the feeder system until the Ground Fault Detector meters, shown in Figure 4, read in the normal range. Note that these switches cannot be instrumented to simplify a polarizing source automation scheme.

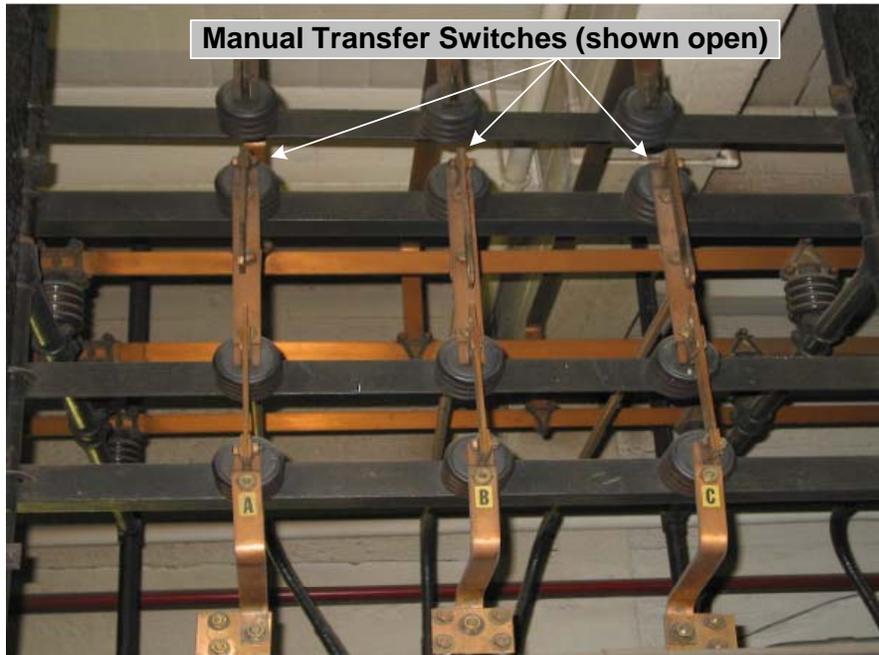


Figure 5 4.8 kV Manual Transfer/Disconnect Switches Are Not Instrumented

Figure 6 shows one bay of power transformers and the space confinements of the associated indoor bus work. Because the apparatus and associated bus work are inside the building, there is very little room for additional instrumentation. As we discuss in the next sections, LADWP is adding the requisite core-flux summing transformers to each feeder for the purpose of measuring zero-sequence current.



Figure 6 Power Transformer Bay and Overhead Bus Work Are Compact

UNGROUNDING OR ISOLATED-NEUTRAL SYSTEMS

The main goals of system grounding are to minimize equipment voltage and thermal stresses, provide personnel safety, reduce communication system interference, and give assistance in rapid detection and elimination of ground faults.

With the exception of voltage stress, operating a system as ungrounded restricts ground fault current magnitudes and achieves most of the goals listed above. One drawback of this grounding method is that it also creates fault detection (protection) sensitivity problems. We can create a system grounding that reduces voltage stress at the cost of large fault current magnitudes. However, in such a system the faulted circuit must be de-energized immediately to avoid thermal stress, communication channel interference, and human safety hazards. The disadvantage is that service must be interrupted even for temporary faults.

In the isolated-neutral system shown in Figure 7, the neutral (N) has no intentional connection to ground (G): the system is connected to ground through the line-to-ground capacitances. Single line-to-ground faults shift the system neutral voltage but leave the phase-to-phase voltage triangle intact.

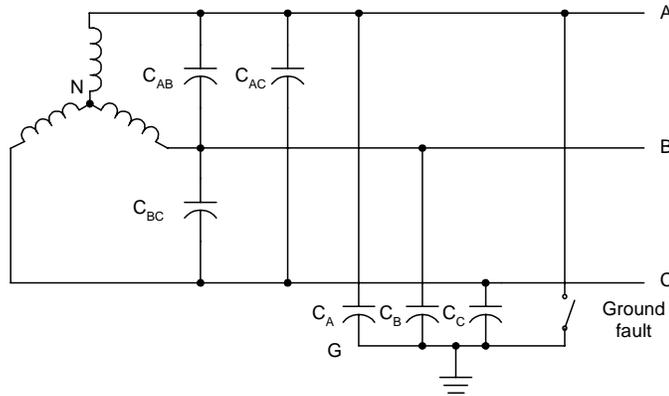


Figure 7 Isolated-neutral System Diagram

For these systems, two major ground fault current, magnitude-limiting factors are the zero-sequence line-to-ground capacitance and fault resistance. Because the voltage triangle is relatively undisturbed, these systems can remain operational during sustained, low-magnitude faults.

Self-extinction of ground faults in overhead-ungrounded lines is possible for low values of ground fault current. At higher magnitudes of fault current, faults are less likely to self-extinguish at the fault current natural zero-crossing because of the high transient recovery voltage.

Zero-sequence, or three-phase voltage relays can detect ground faults in ungrounded systems. This method of fault detection is not selective and requires sequential disconnection or isolation of the feeders to determine the faulted feeder. A sensitive, directional ground varmetric element is an alternative to sequential disconnection. This element responds to the quadrature component of the dot product of the zero-sequence voltage and current. Later we introduce a new directional element that uses the measured impedance to differentiate forward and reverse ground fault direction.

NEW GROUND DIRECTIONAL ELEMENT FOR ISOLATED-NEUTRAL SYSTEMS

Ground fault detection methods are typically based on zero-sequence quantities. It is then important to outline a symmetrical-component-domain analysis of ungrounded systems operating in steady-state. If we consider that a ground directional relay relying on phase quantities would be supplied by high ratio phase current transformers (ct), we immediately see that the need to size the phase ct ratio to sustain full load current automatically makes such a design less sensitive than that which can use a lower ratio core-flux summing ct.

The zero-sequence impedance of an ungrounded system has a very high magnitude. This high value permits us to ignore the positive- and negative-sequence impedances without significant loss of accuracy when evaluating single line-to-ground faults. Figure 8 shows an approximate zero-sequence representation of a forward ground fault in an isolated-neutral system.

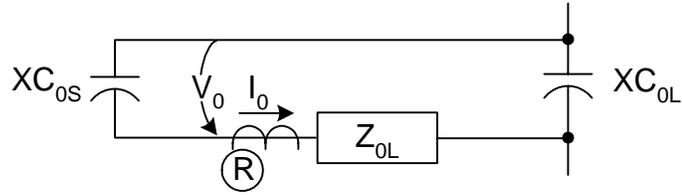


Figure 8 Zero-Sequence Network for the Forward Ground Fault

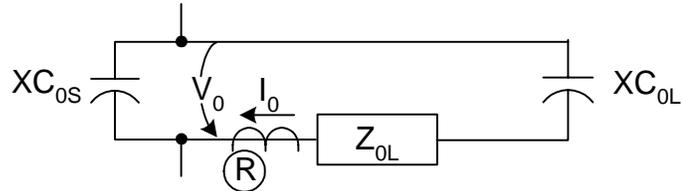


Figure 9 Zero-Sequence Network for the Reverse Ground Fault

Note that in Figure 8 the relay measures V_0 across and the current through XC_{0S} , where XC_{0S} is the zero-sequence impedance of the remaining system behind the relay [8]. Note that in Figure 9 the relay measures V_0 across and the current through the series combination of $(Z_{0L} + XC_{0L})$, where Z_{0L} is the zero-sequence line impedance and XC_{0L} is the distributed line-ground capacitance of the protected line. Thus, the relay measures $-XC_{0S}$ for forward faults and $(Z_{0L} + XC_{0L})$ for reverse faults.

Figure 10a shows the phasor diagram for forward and reverse faults in the system. Figure 10b shows a patent pending directional element characteristic for ungrounded systems. The function of a directional element is to determine forward and reverse conditions: i.e., differentiate $-XC_{0S}$ from XC_{0L} . This new element does this with two separately settable thresholds set between these two impedance values. If the measured impedance is above the forward threshold (and all of the supervisory conditionals are met), the fault is declared forward.

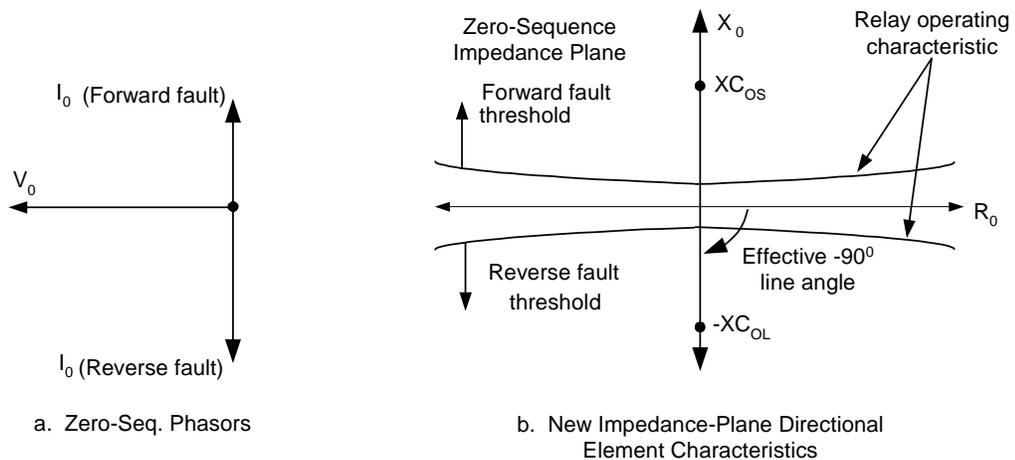


Figure 10 New Ground Directional Element Characteristics

SYSTEM UNBALANCE AFFECTS SENSITIVITY

CT inaccuracies could adversely affect directional element sensitivity. Similarly, if the line-ground capacitances are not equal, the system produces standing or un-faulted zero-sequence quantities. Typically these quantities are small but in a very large system, the cumulative effect of unequal capacitances can generate appreciable zero-sequence voltage. To preserve fault resistance sensitivity, a zero-sequence overvoltage element should not be used to supervise the directional element.

Let us review the effect of zero-sequence voltage supervision on ground relaying sensitivity. For this example, assume the end-of-line ground fault shown in Figure 11 delivers 5 mA of secondary current to the relay on a system where the nominal secondary line-neutral voltage is 66.4V.

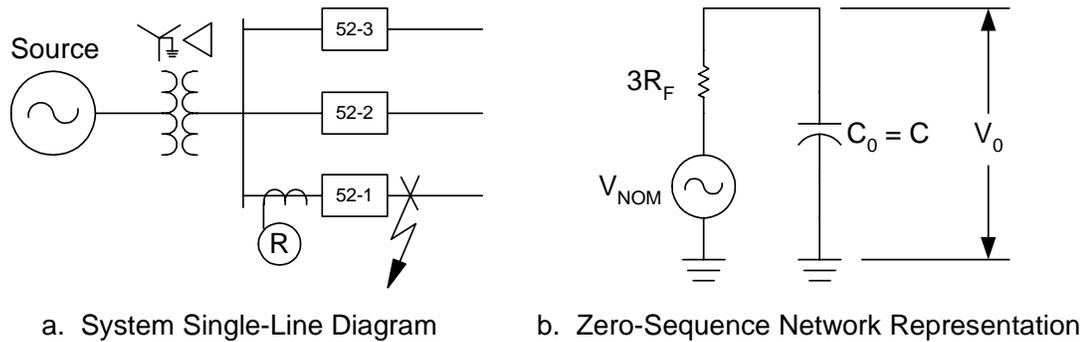


Figure 11 Zero-Sequence Overvoltage Sensitivity Example

From Figure 11b:

$$V_0 = I_0 \cdot \frac{1}{j\omega \cdot C} \quad (1)$$

$$C = \frac{I_0}{j\omega \cdot V_0} \quad (2)$$

Let us next set the minimum V_0 at 2V for a starting place to calculate C in Equation 2 given a minimum I_0 of 5 mA. Doing this for a 60 Hz system, then $C = 6.63 \mu\text{F}$. Next let us evaluate another similar system but with Breaker 3 (52-3) closed to increase C . If this new system only produced 5 mA secondary and the capacitance equaled $13.26 \mu\text{F}$ then $|V_0| = 1\text{V}$ secondary. Given a $3V_0$ threshold of 6V secondary, a relay using supervisory zero-sequence overvoltage would not operate due to an incorrect supervisory setting.

Looking again at Figure 11, we can calculate R_F as:

$$R_F = \frac{V_{\text{NOM}} - V_0}{3 \cdot I_0} \quad (3)$$

From Equation 3, raising the V_0 threshold decreases the numerator and thereby decreases the available fault resistance coverage (or sensitivity) for a given minimum magnitude of I_0 . An alternative to $3V_0$ security supervision is to require the ratio of residual current to positive-sequence current to exceed a minimum scalar threshold value. The benefit of this

supervision is that the minimum sensitivity of each feeder relay is not dependent upon the total system unbalance.

IMPROVED BROKEN DELTA VOLTAGE TRANSFORMER CONNECTION

Before we describe the polarizing voltage selection scheme, let us discuss the zero-sequence polarizing source voltage instrumentation transformers.

The problem centered on the available voltage transformers (vts). The available vts are open-delta at the feeders and broken delta on the various power transformer secondaries. The open-delta vts were located on the line-side of each feeder breaker and the broken-delta vts on the low-voltage side of each power transformer. The broken-delta vt connection does provide zero-sequence voltage for measurement during ground faults, the nominal output voltage for a bolted ground fault on the ungrounded system was $360V_{AC}$: nominal voltage input transformers are rated and scaled for $300V_{LN}$. Further, the application required maintaining the broken delta vt connection for existing protection devices while they verified the validity of any new scheme.

Figure 12 shows the two possible means of wiring the protective relays and metering to open-delta vts. The open-delta vt connection only presents the relays with phase-phase voltages and thus effectively filters out any zero-sequence voltage: note the lack of a V_0 term in Equations 7–9.

$$V_A = V_{A1} + V_{A2} + V_0 \quad (4)$$

$$V_B = a^2 \cdot V_{A1} + a \cdot V_{A2} + V_0 \quad (5)$$

$$V_C = a \cdot V_{A1} + a^2 \cdot V_{A2} + V_0 \quad (6)$$

$$V_{AB} = V_A - V_B = (1 - a^2) \cdot V_{A1} + (1 - a) \cdot V_{A2} \quad (7)$$

$$V_{CB} = V_C - V_B = (a - a^2) \cdot V_{A1} + (a^2 - a) \cdot V_{A2} \quad (8)$$

$$V_{CA} = V_C - V_A = (a - 1) \cdot V_{A1} + (a^2 - 1) \cdot V_{A2} \quad (9)$$

Where:

- V_A = A-Phase Voltage
- V_B = B-Phase Voltage
- V_C = C-Phase Voltage
- V_{AB} = AB Phase-Phase Voltage
- V_{CB} = CB Phase-Phase Voltage (note that V_{CB} is 180° out-of-phase with V_{BC})
- V_{CA} = CA Phase-Phase Voltage
- V_{A1} = Positive-Sequence Voltage: $1/3 \cdot (V_A + a \cdot V_B + a^2 \cdot V_C)$
- V_{A2} = Negative-Sequence Voltage: $1/3 \cdot (V_A + a^2 \cdot V_B + a \cdot V_C)$
- V_0 = Zero-Sequence Voltage: $1/3 \cdot (V_A + V_B + V_C)$

To address the higher nominal voltage, we considered changing one relay vt input to a higher nominal voltage. However, doing so would mean sacrificing accuracy at the lower input voltage levels due to input transformer errors (e.g. 1V input to a 300V nominal transformer with 100 turns has a greater accuracy than 1V input to a 600V nominal transformer with 200 turns).

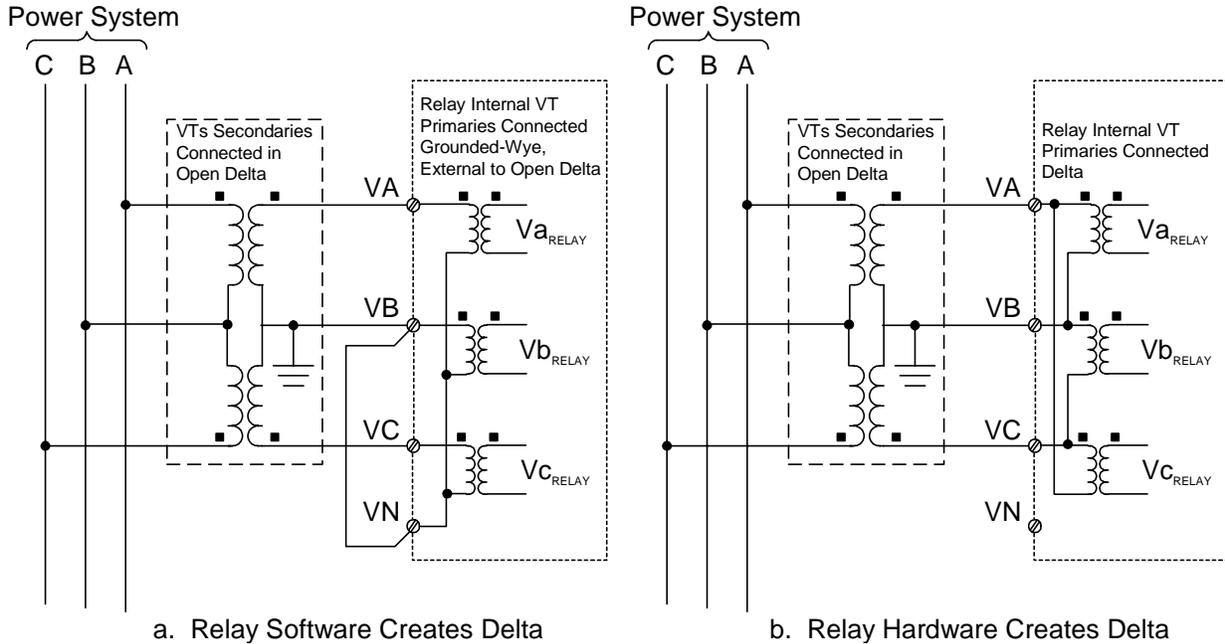


Figure 12 Common Methods of Connecting Open Delta VTs to Protective Relays

We also wanted a relaying system that is also applicable in systems with the vts connected three-phase, four-wire (i.e. no broken delta connection required). Figure 13 shows the resulting connection diagram.

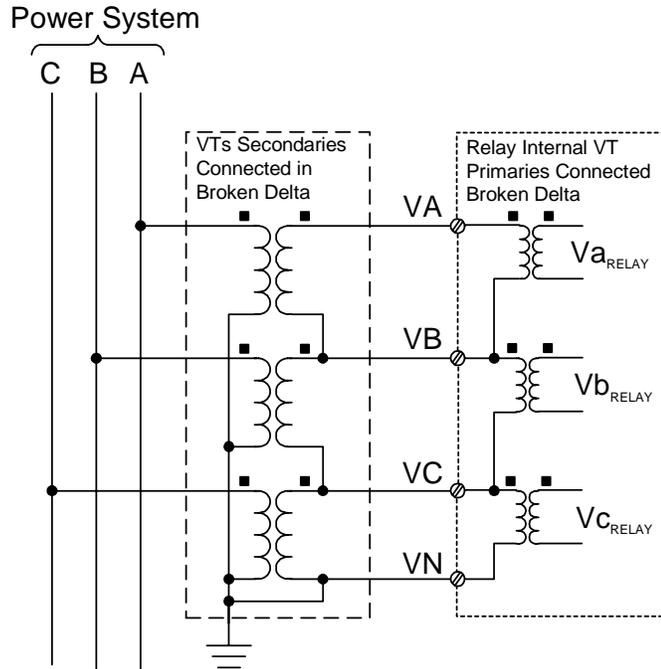


Figure 13 Single-Line and VT Connection Diagram

With the relay input transformers connected as shown, the relay is then able to extract the individual phase voltages. From these phase voltages, we can then calculate $3V_0$.

The benefits of this approach are:

No relay input transformer must be rated for $360V_{AC}$: lower ratios improve sensitivity.

The relay system can now check for blown potential fuses. In a relay using the traditional broken-delta connection on a system with little or no unbalance, the $3V_0$ measurable before and after a blown secondary fuse is the same (i.e., zero volts).

The relay can measure each individual phase voltage and calculate the necessary sequence components. This allows the relay to use the same vts for phase and ground directional control elements.

It does not require disturbing existing wiring for devices using the broken-delta voltage output. Simply add wires from the B- and C-Phase polarity marks of the vt secondaries to the respective inputs on the relay.

It allows dual phase directionality from differing vts: Main 1 could use this new connection from the broken-delta system while Main 2 could use the existing open-delta vts for polarizing.

$3V_0$ POLARIZATION PROBLEMS IN MULTISOURCE, ISOLATED-NEUTRAL SYSTEMS

Figure 14 depicts a medium-sized distribution substation for the LADWP system. Substations may have up to five incoming subtransmission lines (ranging from 34.5 to 115 kV). A double-bus arrangement and a set of disconnects permit connecting any substation transformer and any outgoing feeder to any bus section. This flexibility was very useful in deciphering which was the faulted feeder. Disconnects are not instrumentable. Broken-delta connected voltage transformers provide $3V_0$ information at the 4.8 kV side of each substation transformer. Open-delta connected voltage transformers installed at the feeders do not provide $3V_0$ information for feeder relay polarization. Then, we need to use the substation-transformer $3V_0$ signals to polarize the feeder relay directional elements.

The flexibility of the substation configuration represents a problem to select the $3V_0$ polarizing source for the relays installed at the feeders: which transformer (or transformers) is the relay feeder connected to at the moment of a ground fault?

For example, when the disconnects are in the positions shown in Figure 14, Transformer T1 is connected to Feeders 4 and 5, Transformer T2 is tied to Feeders 6 and 7, and Transformer T3 is connected to Feeders 8 and 9. For a ground fault at some place of the circuit fed by Transformer T3, for example, we need the relays of Feeders 8 and 9 to be polarized with the $3V_0$ signal obtained at the secondary side of Transformer T3. All the other feeder relays do not see any fault current, so their $3V_0$ polarization voltage is not relevant. During the fault we may use the $3V_0$ signal of Transformer T3 to polarize those relays. However, if Transformer T3 is out of service, we may use disconnects to connect feeders 8 and 9 to Transformer T1, (for example). For a ground fault at one of these feeders, we need their feeder relays to be polarized with the $3V_0$ signal from T1.

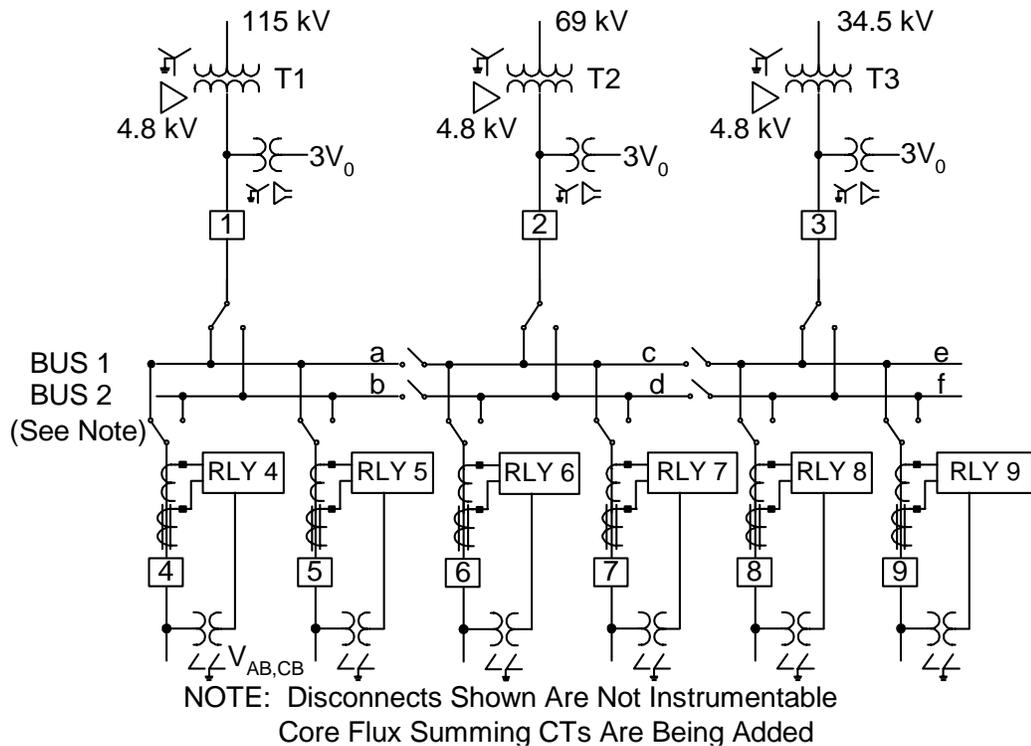


Figure 14 Typical Substation of Los Angeles Urban Distribution System

AN ADAPTIVE SOLUTION TO THE $3V_0$ POLARIZATION PROBLEM

The feeder relays have only one $3V_0$ input. It is then necessary to implement an external logic scheme to provide the relay with the correct $3V_0$ information. There is no logic information available about the disconnect states (no disconnect auxiliary contacts available). We then need to measure the $3V_0$ signals available at the transformers and use that information to select the $3V_0$ signal corresponding to the faulted system section.

It is interesting to note that we must use a mixture of relays calculating and measuring $3V_0$. Those relays connected to the $3V_0$ vts use the improved connection described earlier while the individual feeder relays measure $3V_0$ from a polarizing bus.

System Modeling for Scheme Validation

Figure 15 shows the system we modeled to help validate the proposed scheme. Note that this system is very similar to that shown in Figure 14. Our prime interests from the modeling results were the pre-fault and fault zero-sequence voltages and currents.

For modeling the 4.8 kV system feeders, we used typical LADWP conductor arrangements and conductor parameters. Because information concerning the distribution of loads along the feeders is not readily available, we lumped all loads at the line ends. To simulate the fact that not all loads and conductors are three-phase and balanced, we included an unbalanced, high resistance wye-connected resistance in parallel with the balanced feeder load model [1].

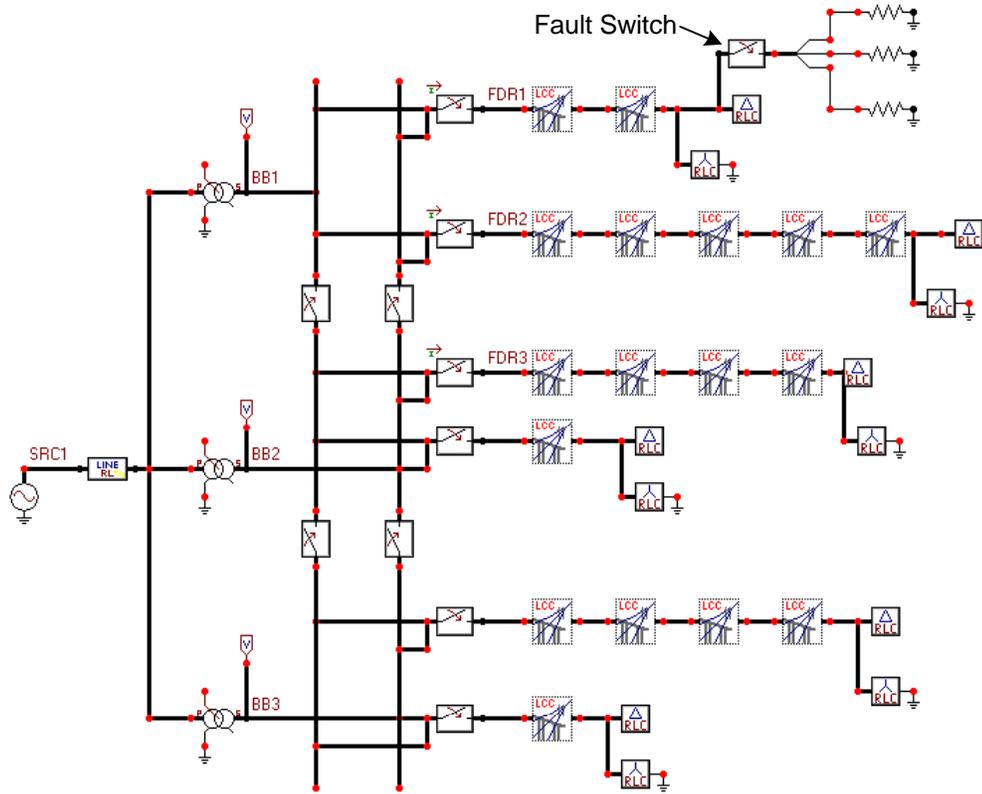


Figure 15 Model System Single-Line Diagram

The new polarizing source selection scheme uses the change in measured $3V_0$ in determining the optimal zero-sequence voltage polarizing source location. In arriving at our solution, we reviewed the validity of measuring all the $3V_0$ magnitudes, comparing them, and then selecting the largest $3V_0$ as that belonging to the faulted system section (assuming that the bus tie switches are open and we have several independent circuits in the system). This method might work well for low-impedance ground faults in balanced systems. However, system unbalance shifts the system neutral under normal operating conditions. The small additional unbalance created by a high-impedance ground fault could shift the system neutral in the direction of a more balanced condition. In other words, the fault could enhance the system balance thus reducing (rather than increasing) the $3V_0$ magnitude. Then, the system section having the largest $3V_0$ magnitude is not necessarily the faulted system section. Figure 16 shows the zero-sequence voltages measured at vt locations BB1, BB2 and BB3 of Figure 15. From Figure 16, notice that $3V_0$ values are not equal: ranging from $50V_{0-PK}$ to $250V_{0-PK}$ primary. If we change the system loading, the $3V_0$ values can also change.

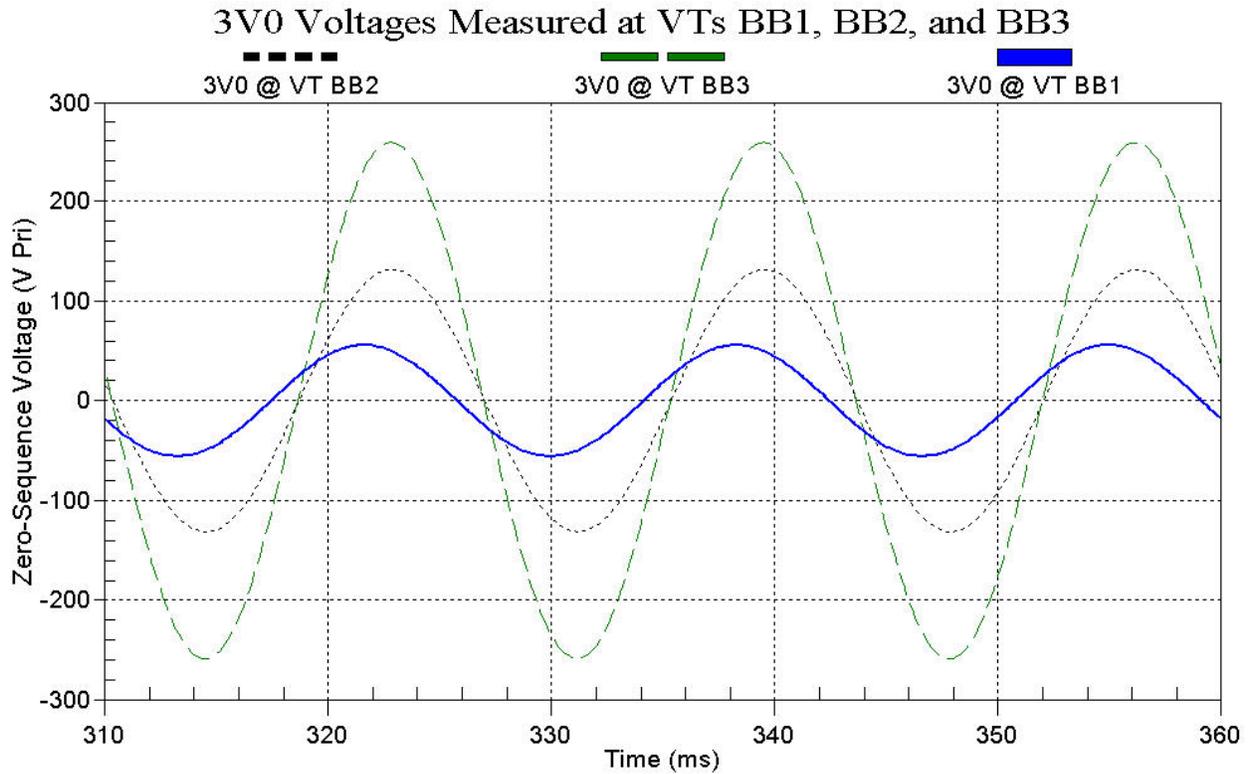


Figure 16 Prefault Zero-Sequence Voltages Are Not Necessarily Balanced

For scheme security, directional elements should not be picked up under normal load conditions. Figure 17 shows the prefault zero-sequence currents measured by the relays for Feeders 1–3. Notice from the figure that the magnitudes of zero-sequence currents are very low. If we assume a 10:1 core-flux summing transformer ratio, the secondary $3I_0$ current presented to the relays is far below a $5 \text{ mA}_{\text{RMS}}$ minimum threshold. Thus, a directional element requiring this minimum current would not pickup for load conditions. Supervising the ground directional element with the requirement that $|I_0| / |I_{A1}|$ exceed a minimum threshold further increases scheme security.

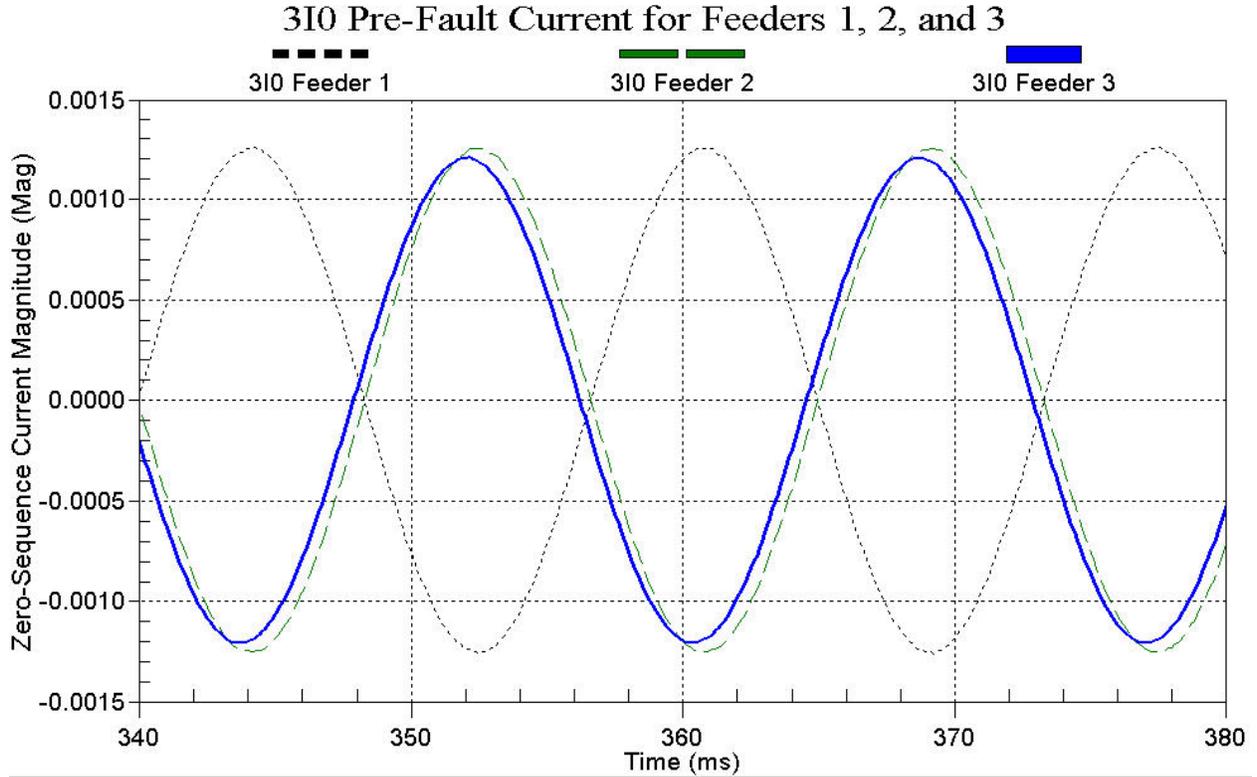


Figure 17 Prefault Zero-Sequence Currents Have Low Magnitudes

To see the difference (delta) zero-sequence voltages presented to relays measuring the $3V_0$ voltage at locations BB1, BB2, and BB3, let us next place a bolted C-Phase fault at the end of Feeder 1 shown in Figure 15. Figure 18 shows the resulting $3V_0$ voltages calculated by relays at BB1, BB2, and BB3. From the data shown in Figure 18, you can immediately determine that BB1 is the appropriate zero-sequence polarizing source.

From the prefault data we showed earlier, it is clear that the better alternative to absolute $3V_0$ magnitudes is to calculate the incremental zero sequence voltage [7], ΔV_0 , as:

$$\Delta V_0 = V_{0, \text{FAULT}} - V_{0, \text{PRE-FAULT}} \quad (10)$$

Where $V_{0, \text{FAULT}}$ is the present value of V_0 and $V_{0, \text{PRE-FAULT}}$ is the V_0 value measured 15 samples before the present value, where 16 samples covers one power system cycle.

We may compare the ΔV_0 values of all the sources and select the largest ΔV_0 value as that belonging to the faulted section of the system. We may then use the $3V_0$ of that source as the polarizing quantity of the feeder relays for that particular fault condition.

We can now summarize the proposed adaptive logic as follows:

Measure $3V_0$ at all substation transformers.

Calculate the incremental zero-sequence voltage, ΔV_0 , at each processing instant, for each substation transformer.

Compare the ΔV_0 magnitudes of all substation transformers.

Declare the substation transformer having the largest ΔV_0 magnitude as the transformer connected to the faulted system section.

Use the $3V_0$ of the faulted system section as the feeder relay polarizing quantity.

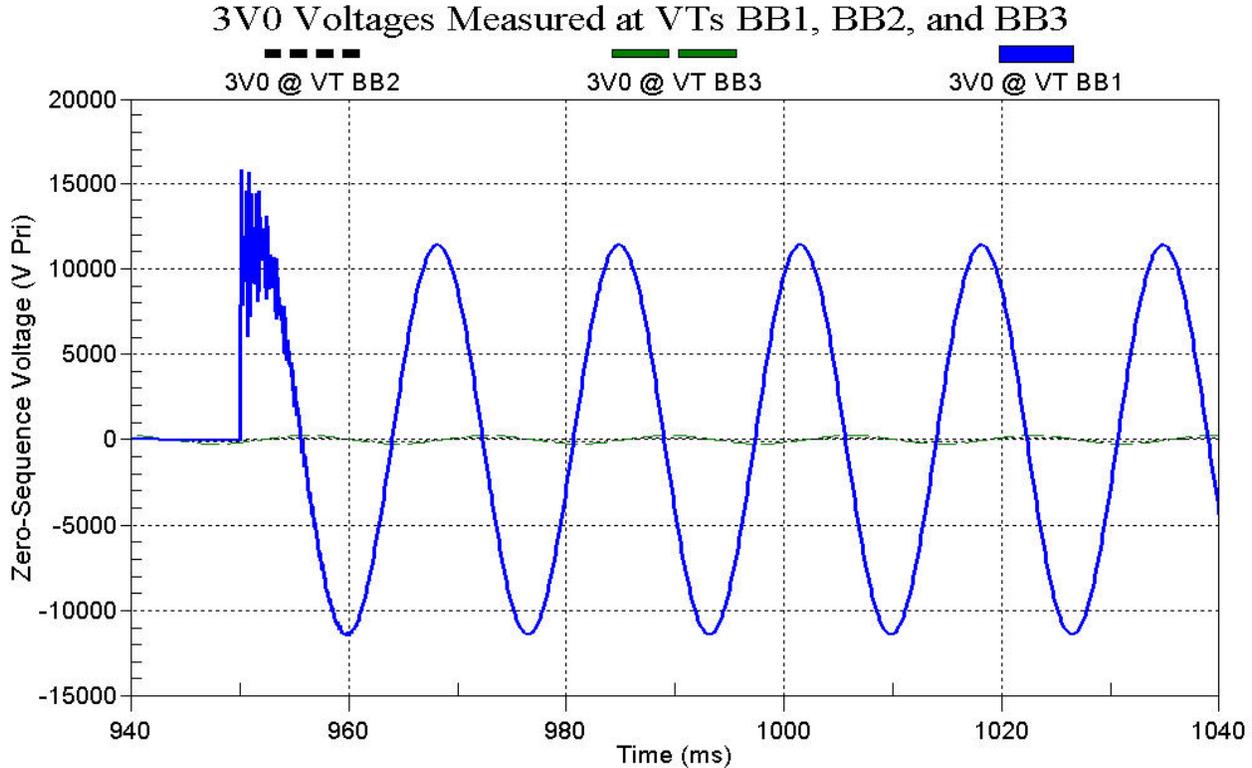


Figure 18 Ground Faults Generate Large Delta $3V_0$ Signals

IMPLEMENTATION OF THE ADAPTIVE LOGIC

Figure 19 depicts the system equipment required to implement the adaptive logic. Relays 1, 2, and 3 calculate the zero-sequence voltages on the low-side delta connected power transformer windings. Relays 1, 2, and 3 use the modified broken-delta connection for the voltage inputs. As a minimum, these three relays communicate their measured voltages to the communications processor. The communications processor compares the ΔV_0 magnitudes from Relays 1, 2, and 3. This same processor next determines the largest ΔV_0 value and declares the corresponding $3V_0$ as the polarizing voltage source for the feeder ground directional elements. The communications processor acts on a control switch that directs the $3V_0$ ground directional polarizing signal to all the feeder relays via the $3V_0$ Bus.

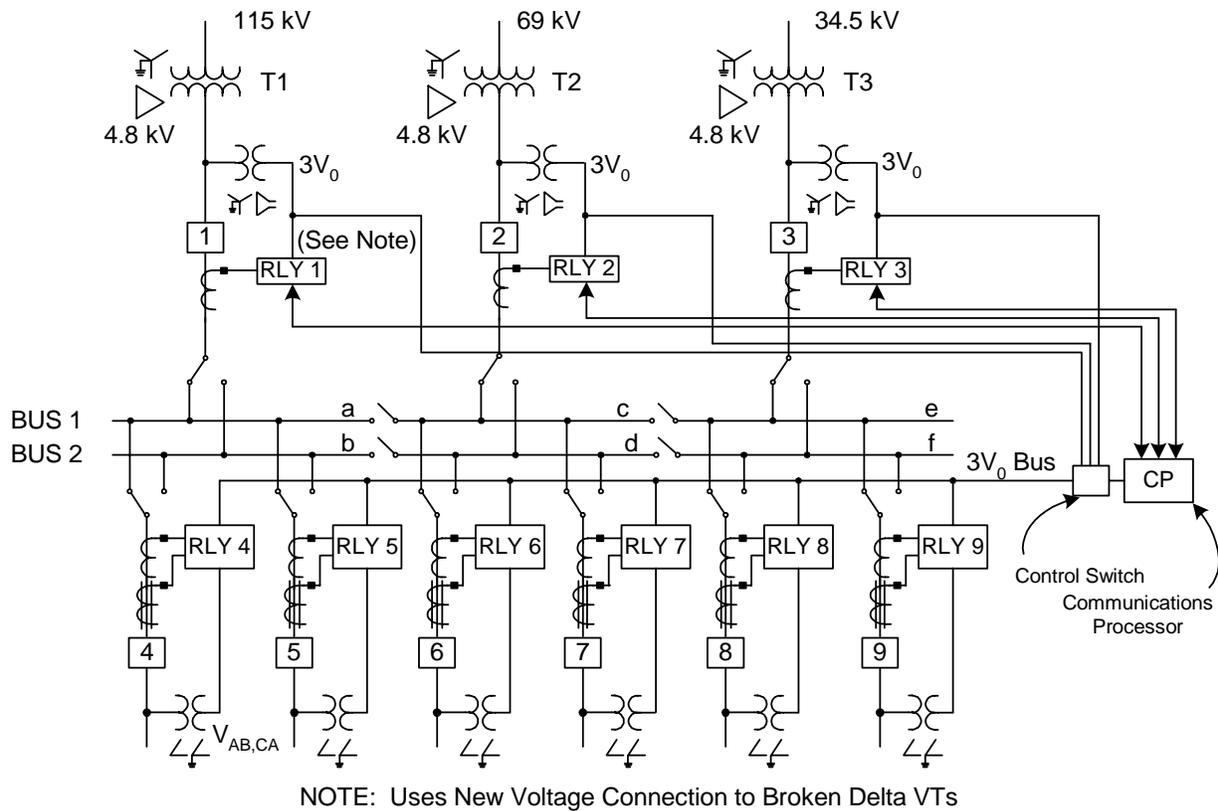


Figure 19 Adaptive Solution Uses Feeder Relays and a Communications Processor

COMMUNICATIONS PROCESSOR PERFORMS AUTOMATION FUNCTIONS

The communications processor (CP) serves as an interface to SCADA for metering and breaker control. In addition, the programmability and integral output contacts make possible the scheme described above. The major roles of the CP are to continuously run two main routines: Determine Delta and Compare Delta. Figure 20 shows the flow-charts for these two routines running in the CP.

The Determine Delta Routine runs on each communications processor (CP) connected to relays associated with transformer low-voltage windings: Relays 1, 2, and 3 in Figure 19. The CP uses two automatic messages (with a 1 second offset) to determine the magnitude difference of the $3V_0$ voltage received from the connected relays. The CP uses Math/Move settings to determine if the calculated delta exceeds a user defined filter value. If the delta exceeds a threshold, the processor sets a fault alarm to notify the SCADA master of a fault condition. This same delta is passed to the Compare Routine of the CP for the purpose of determining the largest delta voltage amongst the relays measuring the zero-sequence voltage transformer outputs (i.e., the relays connected to the transformer low voltage windings). Once the CP determines which relay has the largest delta, it closes an output contact to direct the selected $3V_0$ source to the $3V_0$ Bus shown in Figure 19.

If the CP determines that multiple $3V_0$ measurements exceed the CP filter value, it sets a fault alarm for each of the relays but still uses the $3V_0$ source associated with the relay having the largest delta. All fault alarms are reset from the SCADA master.

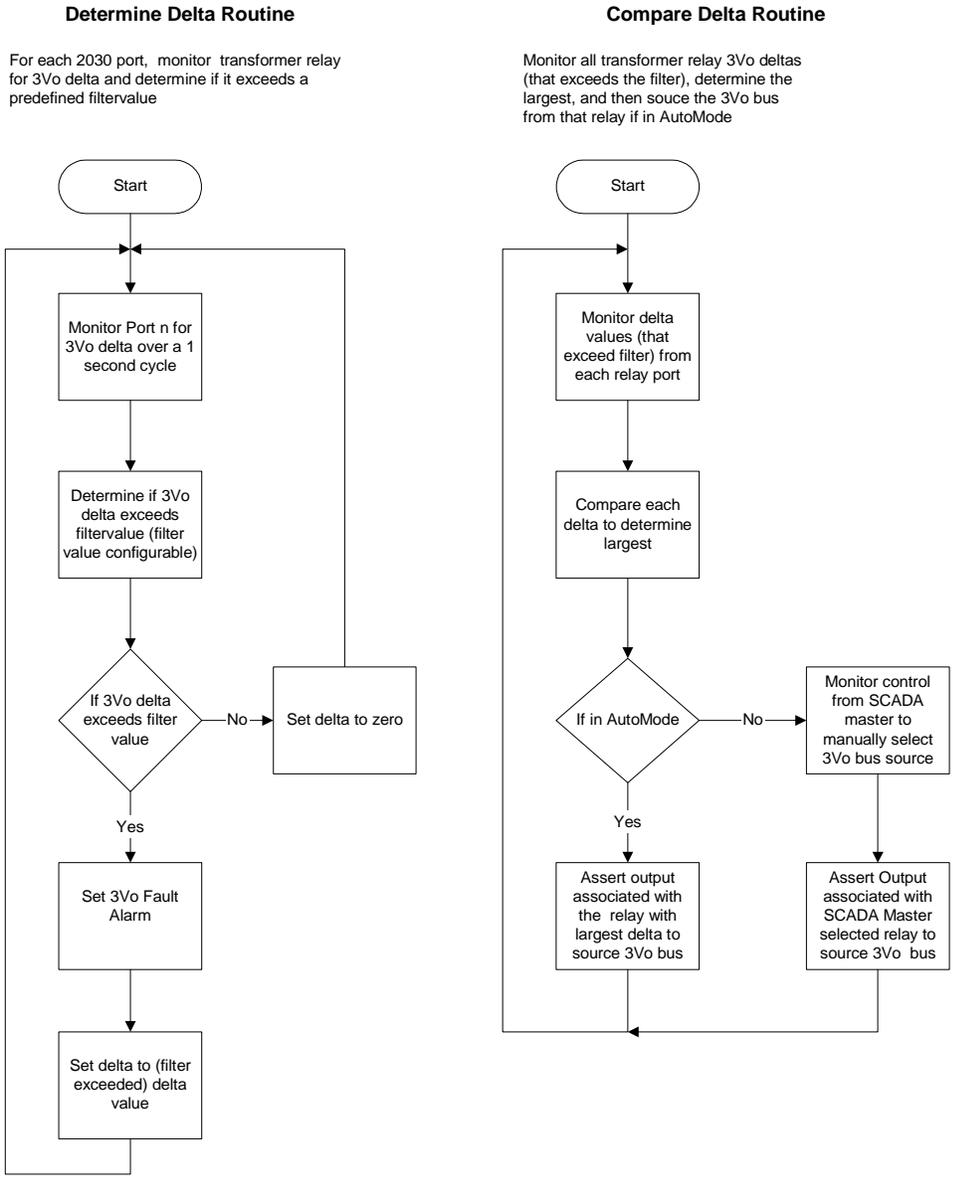


Figure 20 Determine Delta and Compare Delta Routine Flowcharts

Two CP ports are setup to communicate with separate SCADA masters. One port uses automatic messages and a server to provide monitoring and control for a local HMI. The second CP port supports a remote DNP master. The SCADA masters can monitor the transformer relays for instantaneous $3V_0$, delta $3V_0$, fault alarms, which $3V_0$ source is presently selected, and the status of the Auto/Manual mode. Using relay programmable logic and control commands, either SCADA master can force the manual selection of the $3V_0$ source.

GROUND DIRECTIONAL ELEMENT PERFORMANCE

A motivating reason for LADWP to begin investigating adding ground directional protection for their 4.8 kV feeders was the ability to automatically ascertain the faulted feeders. Avoiding the systematic switching of feeder circuits will result in appreciable operating savings.

Let us next investigate the performance of the directional element described earlier in this paper for two C-Phase ground fault scenarios on Feeder 1: 1. Fault resistance (RF) equal to zero, and 2. RF = 10,000 Ω primary. The fault location is at the end of Feeder 1. For both fault cases, we review the performance of the directional element for Feeder Relays 8 and 9 shown in Figure 19.

Case 1: C-Phase Fault, RF = 0 Ω

Figure 21 shows the zero-sequence ($3I_0$) current presented to Relays 9 (Feeder 1), 8 (Feeder 2), and 7 (Feeder 3). For these tests, we minimized the available fault current by opening the bus sectionalizing disconnects: i.e. only Relays 8 and 9 should sense any zero-sequence fault current. From Figure 21, notice that the $|3I_0|$ measured by both relays is identical. This is expected because the A- and B-Phase line-ground capacitances of Feeder 2 serve as paths for zero-sequence current to flow for this fault: both relays sense the current from the same source. In Figure 21, you can see that $3I_0$ for Feeder 2 is 180° out-of-phase with that of Feeder 1. From this we expect the directional decisions for Relay 8 and 9 to be opposite. The magnitude of primary current is 130 mA_{0-PK}. Given an assumed core-flux summing current transformer ratio of 10:1, this means that Relays 8 and 9 are presented with over 9 mA_{RMS} of secondary current. Notice that the zero-sequence current measured by Relay 7 on Feeder 3 current is far below the minimum current sensitivity threshold for the ground directional element: the ground directional element is blocked from operating.

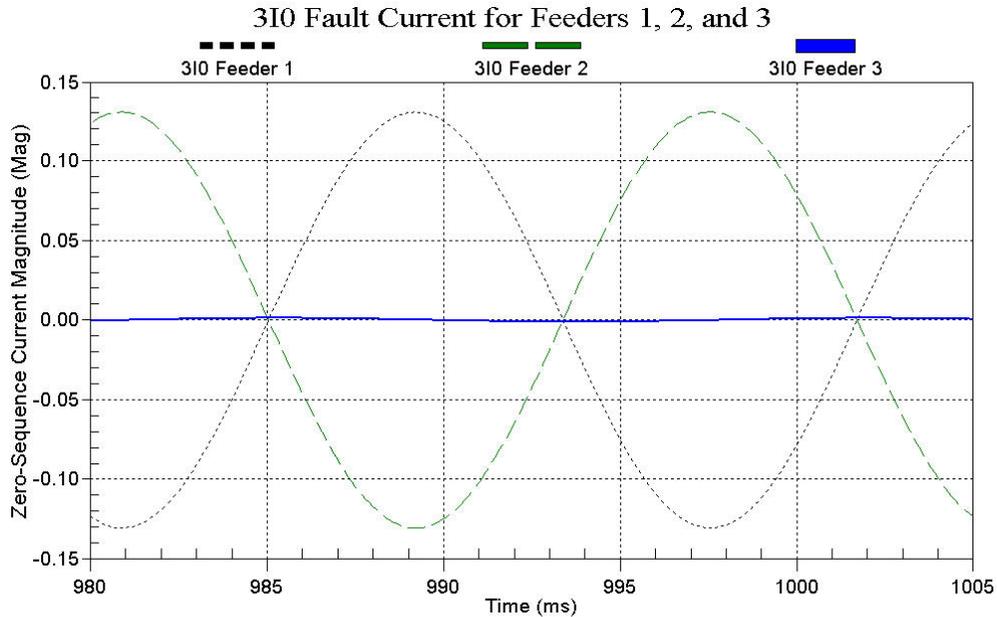


Figure 21 Zero-Sequence Currents Measured by Relays 7, 8, and 9 for Case 1

Figure 22 shows the calculation results performed by the ground directional element described earlier in this paper. The directional calculation (Z_0) result is positive for Relay 9 and well above the minimum 0.01 Ω forward threshold. Because $3I_0$ for Relay 8 has the same magnitude but opposite sign as that for Relay 9, the resulting directional calculation for Z_0 in Relay 8 has the same absolute magnitude but negative sign. This negative and large Z_0 result is much more negative than the reverse directional threshold and Relay 8 declares a reverse fault.

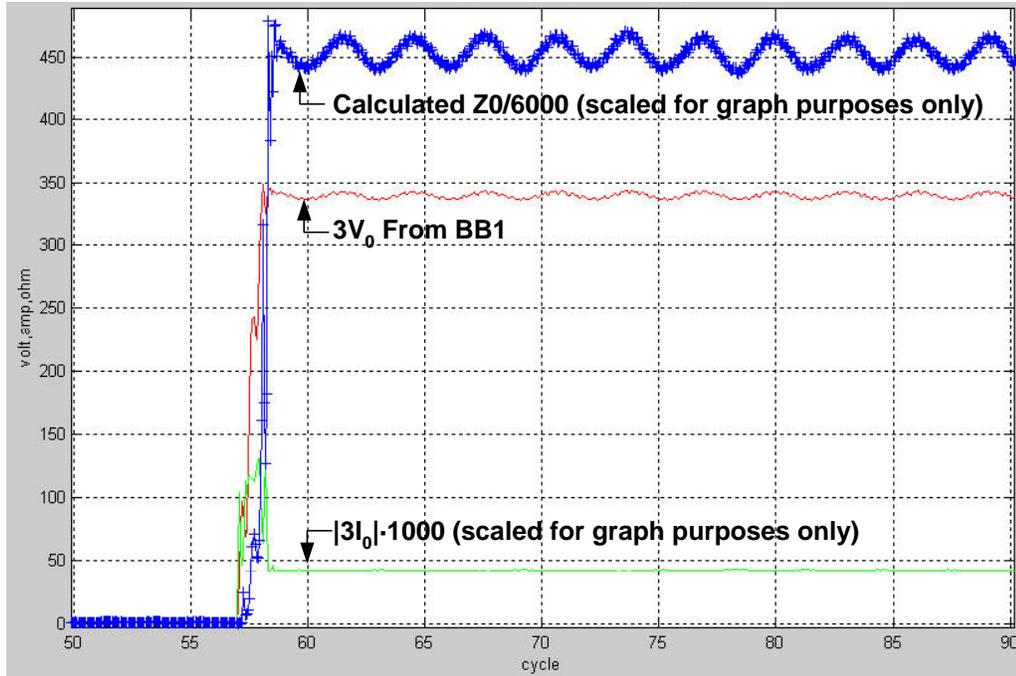


Figure 22 Feeder 1 Forward Declaration for C-Phase Fault w/ $R_F = 0 \Omega$

From an operational perspective, the system operators need only concern themselves with forward ground faults. Without having to systematically switch feeder circuits, the operator is notified (via front panel indications or SCADA information) that Feeder 9 is the circuit with a ground fault. These same microprocessor-based relays include faulted phase logic to identify the faulted phase.

Case 2: C-Phase Fault, $R_F = 10,000 \Omega$

Figure 23 shows the zero-sequence ($3I_0$) current presented to Relays 7, 8, and 9 for this fault scenario. The system switching configuration is the same as that for Case 1. From Figure 23, again you can see that $3I_0$ for Feeder 2 is 180° out-of-phase with that of Feeder 1. The magnitude of primary current is only reduced to 111 mA_{0-PK} . Comparing this $|3I_0|$ with that for Case 1, we only reduced the primary $3I_0$ by 19 mA yet we added $10 \text{ k}\Omega$ of fault resistance. The reason for this is the high zero-sequence source impedance. In general, if the $|3I_0|$ for a bolted (i.e. $R_F = 0$) ground fault is above the minimum sensitivity of the ground directional element, the protective relay can sense very high values of fault resistance. For example, if the capacitive source impedance has $30,000 \text{ ohms}$ of impedance, you would need to include over $50,000 \text{ ohms}$ of resistance to create a total zero-sequence impedance sufficient to half the total zero-sequence current.

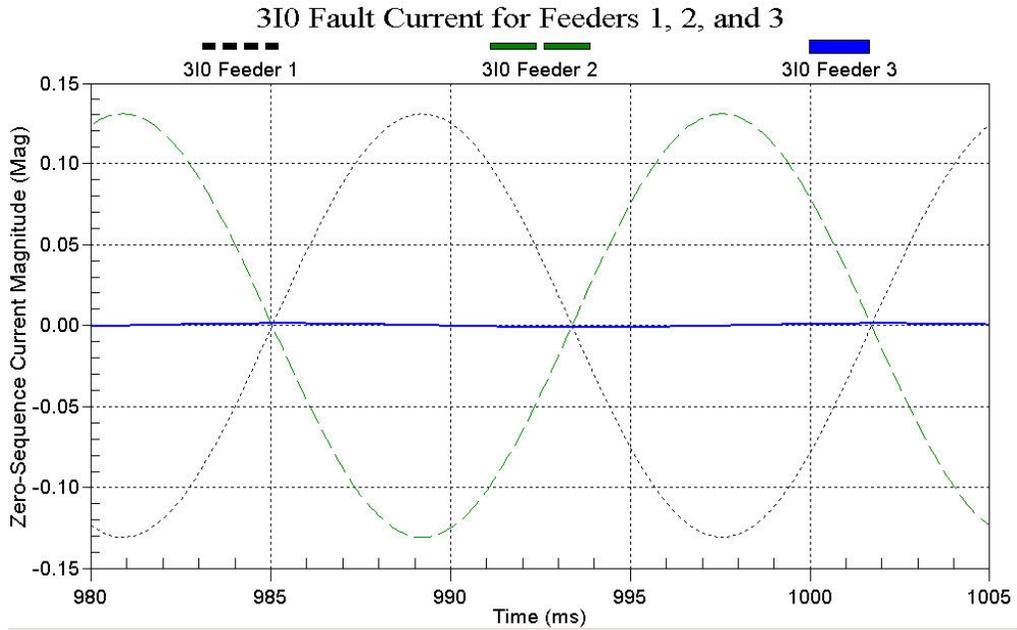


Figure 23 Zero-Sequence Currents Measured by Relays 7, 8, and 9 for Case 2

Figure 24 shows the Z_0 calculation results for Relay 9 for this higher resistance fault. Notice that the results are very much like those for the bolted fault case we just reviewed: the resulting Z_0 calculation is positive and well above the 0.01Ω minimum forward threshold. Also like the bolted fault case, Relay 8 declares the fault direction as reverse.

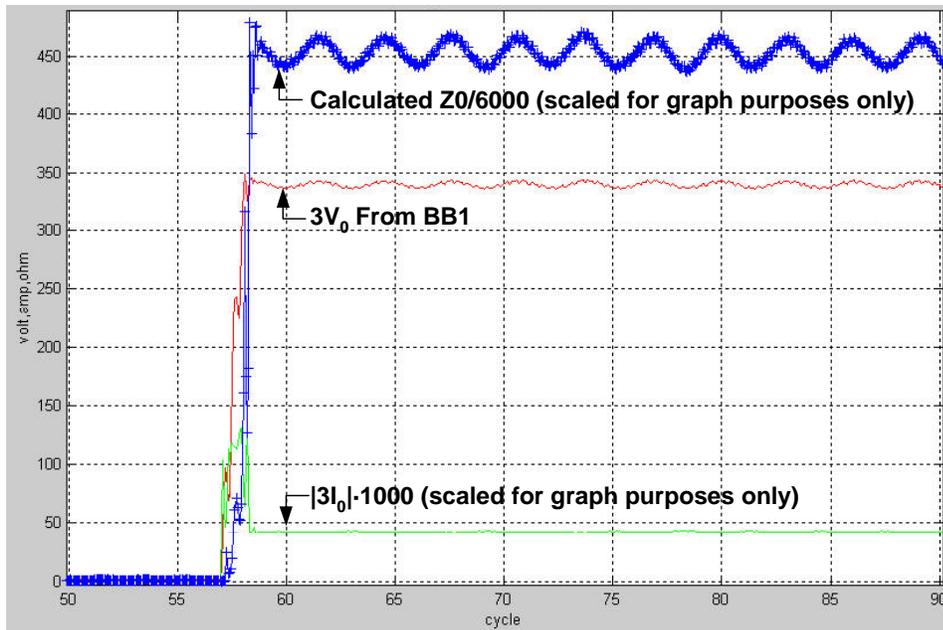


Figure 24 Feeder 1 Forward Declaration for C-Phase Fault w/ $RF = 10,000 \Omega$

CONCLUSIONS

1. Ungrounded systems are connected to ground through the line-to-ground capacitances. Single line-to-ground faults shift the system neutral but leave the phase-to-phase voltage triangle intact. Self-extinction of ground faults in overhead-ungrounded lines is only possible for low values of ground fault current.
2. Zero-sequence, or three-phase voltage relays can detect ground faults in ungrounded systems. However, this method is not selective. A sensitive, directional ground varmetric element is the classic solution to ground fault detection in ungrounded systems.
3. A new ground directional element for ungrounded systems (patent pending) measures the zero-sequence reactance and compares its value with two settable thresholds. For a forward ground fault the element measures the zero-sequence capacitive reactance of the equivalent system behind the relay. For reverse faults the new element measures the series combination of the protected line zero-sequence series impedance and the line capacitive reactance.
4. The new ground directional element includes security supervision logic that requires the ratio of residual current to positive sequence current to exceed a minimum scalar threshold value. The benefit of this supervision as compared to the traditional $3V_0$ security supervision is that the minimum sensitivity of each feeder relay is not dependent upon the total system unbalance.
5. We may extract three-phase, four-wire voltage signals from an existing broken-delta voltage-transformer connection. This patented solution is to connect the relay voltage transformer primaries in broken-delta. With this solution the relay can measure each phase voltage and calculate all the voltage symmetrical components.
6. Some multisource, isolated-neutral systems have zero-sequence voltage information available only at the substation transformers (rather than at the feeders). In such systems it is difficult to obtain a reliable voltage polarizing source for feeder ground directional elements, especially when the substation configuration may change.
7. It is possible to implement an adaptive solution to this problem by combining relays that measure zero-sequence voltage with a communication processor having mathematical and compare features. The communications processor calculates the ΔV_0 values. Using this information the communications processor determines the proper polarization voltage to distribute to the feeder relays.

REFERENCES

- [1] E. T. B. Gross, "Sensitive Fault Protection for Transmission Lines and Distribution Feeders," *AIEE Transactions*, Vol. 60, Nov. 1941, pp. 968–972.
- [2] AIEE Committee Report, "Sensitive Ground Protection," *AIEE Transactions*, Vol. 69, 1950, pp. 473–476.
- [3] Ya. S. Guelfand, *Protection of Distribution Networks*, Moscow: Energoatomizdat, 1987 (Russian).
- [4] A. M. Fedoseev, *Protective Relaying of Electrical Systems*, Moscow: Energia, 1976 (Russian).

- [5] D. Griffel, Y. Harmand, and J. Bergeal, "New Neutral Earthing Technologies on MV Networks," *Revue Generale D'Electricite*, No. 11, December 1994, pp. 35–44 (French).
- [6] L. F. Hunt and J. H. Vivian, "Sensitive Ground Protection for Radial Distribution Feeders," *AIEE Transactions*, Vol. 59, February 1940, pp. 84–90.
- [7] G. Benmouyal and J. Roberts, "Superimposed Quantities: Their True Nature and Their Application in Relays," *Proceedings of the 26th Annual Western Protective Relay Conference*, Spokane, WA, October 26–28, 1999.
- [8] J. Roberts, H. Altuve, and D. Hou, "Review of Ground Fault Protection Methods for Grounded, Ungrounded, and Compensated Distribution Systems," *Proceedings of the 28th Annual Western Protective Relay Conference*, Spokane, WA, October 23–25, 2001.

BIOGRAPHIES

Jeff Roberts is a Research Fellow and Staff Systems Engineer at Schweitzer Engineering Laboratories in Pullman, WA. Prior to joining SEL he worked for Pacific Gas and Electric as a System Protection Engineer. He received his BSEE from Washington State University in 1985 and is now an Associate Professor with the University of Idaho. Mr. Roberts holds 22 patents and has many other patent applications pending concerning relays or system that he created. He has written many papers in the areas of distance element design, sensitivity of distance and directional elements, directional element design, and analysis of event report data. He has delivered papers at the Western Protective Relay Conference, Texas A&M University, Georgia Tech, Monterrey Symposium on Electric Systems Protection, and the South African Conference on Power System Protection. He is a Senior Member of the IEEE and was recognized by the Spokane chapter of the IEEE as Engineer of the Year for 2001. Jeff is also a member of the IEEE Power Engineering Society.

Normann Fischer joined Eskom as a Protection Technician in 1984. He received a Higher Diploma in Technology, with honors, from the Witwatersrand Technikon, Johannesburg, in 1988 and a B.Sc. in Electrical Engineering, with honors, from the University of Cape Town in 1993. He was a Senior Design Engineer in Eskom's Protection Design Department for three years, then joined IST Energy as a Senior Design Engineer in 1996. In 1999, he joined Schweitzer Engineering Laboratories as a Power Engineer in the Research and Development Division. He was a registered professional engineer in South Africa and a member of the South Africa Institute of Electrical Engineers.

Bill Fleming received his B.S. degree in electrical engineering from West Virginia University in 1985, and his M.S. degree in electrical engineering from Virginia Polytechnic Institute and State University in 1991. Mr. Fleming worked as a Protection Engineer for the Potomac Edison Company in Hagerston, Maryland from 1985 to 1996. He joined Schweitzer Engineering Laboratories in 1996 as an Application Engineer. He is an IEEE member.

Robin Jenkins has a BSCE degree from California State University, Chico. From 1984 to 1988, he was employed as a systems integration engineer for Atkinson System Technologies. From 1988 to 1999, he was with the California Department of Water Resources, where he worked as an associate and then senior control system engineer. In 1999, he joined Schweitzer Engineering Laboratories, Inc. where he currently holds the position of integration application engineer, and is responsible for technical support, application assistance, and training for SEL customers in the Southwest United States.

Alan Taylor is the System Protection Design Engineer at Los Angeles Department of Water and Power. Alan graduated from the University of Utah with a BSEE in 1971, and from the University of Southern California with a MSEE in 1976. He has worked in the System Protection Design Group since March 1973.