Limits to the Sensitivity of Ground Directional and Distance Protection

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INTRODUCTION

Relay designers have used analog and digital electronic technology to advance the sensitivity of protective relays while simultaneously decreasing instrument transformer burden. Today, sensitivity is generally not limited by the relays, but instead is limited by the rest of the system: system unbalance, instrument transformer accuracy and ratings, grounding practices, and source strengths.

This paper identifies these limits, analyzes them, and offers practical solutions. Some surprises in this paper include: line asymmetry can cause ground directional elements to misoperate, directional element sensitivity can be worse than the supervised overcurrent element setting, and just how much fault resistance (R_F) is really covered by various ground directional elements.

This paper evaluates sensitivity limits in the following sections:

- Ground directional element sensitivities: How much R_F coverage do various directional elements provide, and how do we calculate this resistance?
- Ground distance element sensitivities: How much R_F coverage do ground distance elements provide?
- Instrument transformers and their connections: How do voltage and current transformer magnitude and phase angle errors and saturation affect R_F coverage?

  Line asymmetry: How do untransposed lines and three-phase faults affect ground directional element fault resistance coverage?

Finally, we discuss practical field checks to determine if factors identified in this paper affect your protection scheme sensitivity and security.

DIRECTIONAL ELEMENT SENSITIVITIES

The sensitivity of a protective system might be expressed by maximum fault resistance coverage.

The sensitivities of individual relay elements depend on voltampere limits, voltage thresholds, and current thresholds. In this section, we discuss directional relay sensitivities and how different combinations of relays with differing sensitivities affect the sensitivity of the complete protective system.

Torque Limits are Frequently Expressed in Voltamperes

In an electromechanical directional element, the sensitivity is often expressed in terms of minimum voltamperes.

Microprocessor relays do not produce physical torque, but instead they frequently calculate a torque-like quantity. The magnitude of this torque-like quantity must cross a minimum threshold before the directional declaration is considered valid. This is analogous to the electromechanical implementation when the operating torque must overcome the restraint of a spring.

Reference [1] discusses many directional elements, their minimum thresholds, and security issues associated with each element. Table 1 is repeated from [1] and shows the inputs to a traditional negative-sequence directional element, and (1) shows the torque expression.

Table 1: Inputs to a Traditional Negative-Sequence Directional Element

Operating Quantity (I_{op})	Polarizing Quantity (V_{pol})
$I_{A2} \cdot (1 \angle Z_{L2})$	$-V_{A2}$

$$T32Q = |V_{A2}| \cdot |I_{A2}| \cdot \cos[\angle -V_{A2} - (\angle I_{A2} + \angle Z_{L2})] \quad (1)$$

where

V_{A2} = Negative-sequence voltage measured by the relay
I_{A2} = Negative-sequence current measured by the relay
Z_{L2} = Negative-sequence replica line impedance

T32Q is positive for forward faults and negative for reverse faults. The magnitude of T32Q must exceed a minimum torque threshold before the directional element is considered valid. This is an intentional security measure in microprocessor relays to avoid making erroneous directional decisions when the magnitude of the operating or polarizing quantity becomes too small to be a reliable measure of direction.

Voltage and Current Thresholds

The general equation for directional element torque can be expressed as $|V| \cdot |I| \cdot \cos(\Theta)$, where one example of Θ is shown in (1). Rather than require a minimum torque threshold, you could simply require a minimum $|V|$ and/or a minimum $|I|$ before considering a directional element decision as valid. If this method of security is selected, these thresholds must be selected very carefully. If the minimum $|V|$ is too high, it severely limits the directional element R_F coverage and makes the directional element useless near strong sources. On the other hand, requiring a minimum current magnitude is a very practical, efficient, and secure method of controlling directional element security.

Examples of Relay Sensitivities

Table 2 lists several published directional element sensitivities.

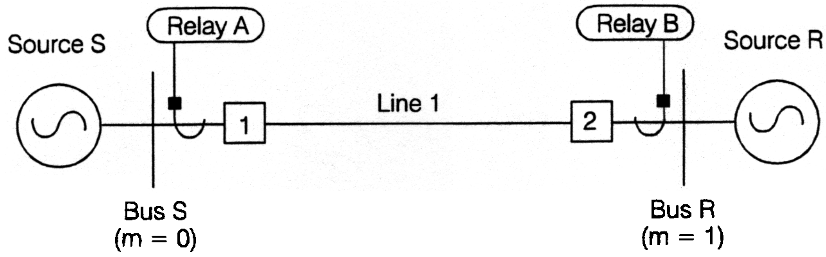
Table 2: Ground Directional Relay Sensitivities Depend on Torque, Impedance, Voltage and/or Current Limits

Directional Element	Directional Element Type	Minimum Torque or Impedance	Minimum V or I
1. SEL-321	Zero-Seq. Z (patent pending, see Appendix A)	Settable: ±64 Ω	$3 \cdot I_{A0} = 0.25$ A and $\lvert I_{A0} \rvert / \lvert I_{A1} \rvert > 0.02 - 0.5$
2. SEL-321	Neg.-Seq. Z (patented)	Settable: ±64 Ω	$3 \cdot I_{A2} = 0.25$ A and $\lvert I_{A2} \rvert / \lvert I_{A1} \rvert > 0.02 - 0.5$
3. SEL-221G/H	Zero-Seq. V	0.145 VA[1]	Pickup of 51N, 50N1 - 50N3
4. SEL-221G/H	Dual Zero-Seq.	0.145 Net Torque [VA or A^2][1]	"
5. SEL-221G/H	Zero-Seq. I	0.22 [A^2][1]	"
6. SEL-221G/H	Neg.-Seq.	0.1 VA	"
7. IRC	Zero-Seq. I	0.25 A^2	$3 \cdot I_{A0} = 0.5$ A
8. IRP	Zero-Seq. V	2 VA	$3 \cdot V_{A0} = 1$ V $3 \cdot I_{A0} = 2$ A
9. Brand X	Neg.-Seq.	0.175 VA	$V_{A2} = 1$ V $I_{A2} = 0.167$ A

Magnitude depends on ground time-overcurrent element pickup threshold. Throughout this paper, the pickup of this threshold is assumed to be 0.5 A secondary.

Directional Element Sensitivities Affect Fault Resistance Coverage

To convert directional element sensitivities into fault resistance (R_F) coverage, we must first assume a system. Consider pairs of directional elements from Table 2, applied to the 90°system of Figure 1.



Source S: $Z_{S1} = 2\ \Omega$, $Z_{S0} = 6\ \Omega$ Line 1: $Z_{L1} = 2.5\ \Omega$, $Z_{L0} = 7.5\ \Omega$ Source R: $Z_{R1} = 1\ \Omega$, $Z_{R0} = 3\ \Omega$

Figure 1: Directional Element R_F Limitation Example System Single-Line Diagram

We can perform some quick calculations, without much loss of accuracy, by realizing that R_F is much greater than that of the protected line.

Directional Element 9, AG Fault Near Bus S

This directional element requires $|V_{A2}| \geq 1$ V and $|I_{A2}| \geq 0.167$ A. Given the simplifying assumption listed above, first consider $|V_{A2}|$ at Relay A.

$$V_{A2,RELAY} = 1\ \text{V}$$

$$Z_{2EQ} \cdot I_{A2} \qquad \text{(where } Z_{2EQ} = (2\ \Omega \,\|\, (2.5 + 1)\ \Omega) = 1.27\ \Omega\text{)}$$

$$1.27\ \Omega \cdot \frac{V_A}{3 \cdot R_F}$$

$$1.27\ \Omega \cdot \frac{66.4\ \text{V}}{3 \cdot R_F}$$

Solving for R_F:

$$R_F = 28.18\ \Omega$$

These simple calculations show $|V_{A2,RELAY}| = 1$ V limits the R_F coverage to 28.18 Ω. What is $|I_{A2,RELAY}|$ measured at Relay A for $R_F = 28.18\ \Omega$?

$$I_{A2,RELAY} = \frac{66.4\ \text{V}}{3 \cdot R_F} \cdot C_{12} \qquad \text{(where } C_{12} \text{ is the current distribution factor } = \frac{(2.5+1)\ \Omega}{(2+2.5+1)\ \Omega} = 0.64\text{)}$$

$$\frac{66.4\ \text{V}}{3 \cdot 28.18\ \Omega} \cdot 0.64$$

$$0.5\ \text{A}$$

Since $|I_{A2,RELAY}|$ is three times the minimum I required, we see that $|V_{A2}| \geq 1$ V limits R_F coverage for this case.

Assuming that $|I_{A0,RELAY}|$ approximately equals $|I_{A2,RELAY}|$ at Relay A, setting a directionally-controlled ground overcurrent element below 1.5 A does not improve R_F coverage for this fault. We still must consider remote terminal faults. Setting the pickup of these ground overcurrent elements below the sensitivity of the directional element is an unnecessary security liability, especially for untransposed line applications.

Directional Element 6, AG Fault Near Bus S

This directional element requires that the negative-sequence directional element torque (T32Q) exceed 0.1 VA for forward faults.

$$\begin{aligned} T32Q &= 0.1\text{ VA} \\ &= V_{A2} \cdot (I_{A2} \cdot 0.64) \\ &= (I_{A2} \cdot Z_{2EQ}) \cdot (I_{A2} \cdot 0.64) \\ &= \left(\frac{66.4\text{ V}}{3 \cdot R_F} \cdot 1.27\ \Omega\right) \cdot \left(\frac{66.4\text{ V}}{3 \cdot R_F} \cdot 0.64\right) \end{aligned}$$

Solving for R_F:

$$R_F = 63.18\ \Omega$$

What is $|I_{A2,RELAY}|$ at Relay A for $R_F = 63.18\ \Omega$?

$$\begin{aligned} I_{A2,RELAY} &= \frac{66.4\text{ V}}{3 \cdot 63.18\ \Omega} \cdot 0.64 \\ &= 0.22\text{ A} \end{aligned}$$

Setting the pickup of a directionally-controlled ground overcurrent element less than 0.66 A does not improve R_F coverage for this fault.

Directional Element 6 has more than twice the R_F coverage as Directional Element 9.

What are the R_F limitations if the AG fault is near Bus R?

Directional Element 9, AG Fault Near Bus R

Following the same steps:

$$V_{A2,RELAY} = 1\text{ V}$$

$$= (Z_{2EQ} \cdot I_{A2}) \cdot C_{V2}$$

(C_{V2}, the voltage divider ratio $= \frac{2\ \Omega}{(2+2.5)\ \Omega} = 0.44$, and $Z_{2EQ} = (2 + 2.5)\ \Omega \parallel 1\ \Omega) = 0.82\ \Omega$)

$$= \left(0.82\ \Omega \cdot \frac{66.4\text{ V}}{3 \cdot R_R}\right) \cdot 0.44$$

Solving for R_F:

$$R_F = 8\,\Omega$$

What is $|I_{A2,RELAY}|$ at Relay A for $R_F = 8\,\Omega$?

$$I_{A2,RELAY} = \frac{66.4\text{ V}}{3 \cdot R_F} \cdot C_{I2}$$

(C_{I2} is the current distribution factor = $\left(\frac{1\,\Omega}{(2+2.5+1)\,\Omega}\right) = 0.18$)

$$= \frac{66.4\text{ V}}{3 \cdot 8\,\Omega} \cdot 0.18$$

$$= 0.5\text{ A}$$

Again, we see that $|V_{A2}| \geq 1$ V limits the R_F coverage. For Directional Element 9 in this application, setting a directionally-controlled ground overcurrent element below 1.5 A does not improve R_F coverage for ground faults anywhere along the line.

Directional Element 6, AG Fault Near Bus R

$$\begin{aligned} T32Q &= 0.1\text{ VA} \\ &= (V_{A2} \cdot C_{V2}) \cdot (I_{A2} \cdot C_{I2}) \\ &= (I_{A2} \cdot Z_{2EQ} \cdot 0.44) \cdot (I_{A2} \cdot 0.18) \\ &= \left(\frac{66.4\text{ V}}{3 \cdot R_F} \cdot 0.82 \cdot 0.44\right) \cdot \left(\frac{66.4\text{ V}}{3 \cdot R_F} \cdot 0.18\right) \end{aligned}$$

Solving for R_F:

$$R_F = 17.8\,\Omega$$

What is $|I_{A2,RELAY}|$ at Relay A for $R_F = 17.8\,\Omega$?

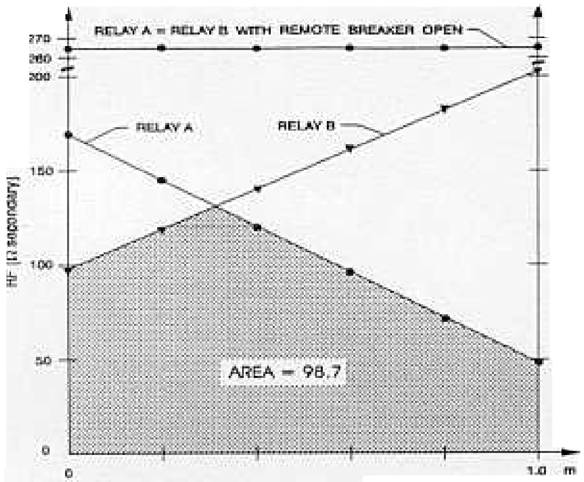
$$I_{A2,RELAY} = \frac{66.4\text{ V}}{3 \cdot 17.8\,\Omega} \cdot 0.18$$

$$= 0.22\text{ A}$$

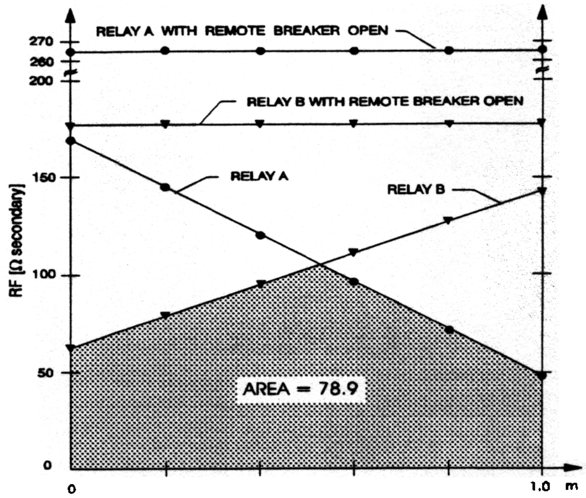
For Directional Element 6, setting the pickup of the directionally-controlled residual overcurrent element below 0.66 A does not improve R_F coverage.

We expect directional elements are installed at both ends of a two-terminal line in a looped or networked system. What is the R_F coverage of the protection system if the same or different directional elements are used in the protective relays at either line end?

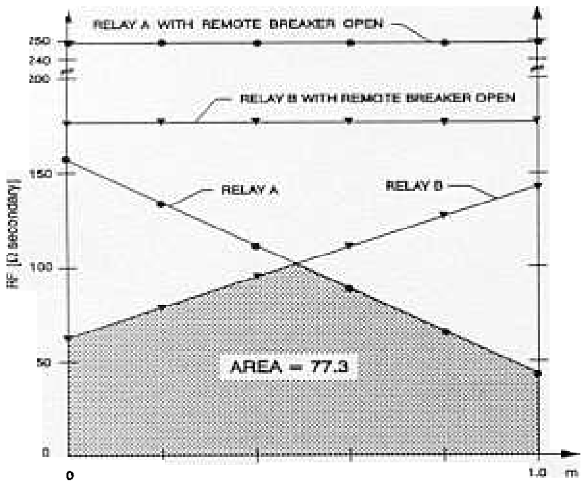
Figure 2 shows the R_F coverage for various combinations of the directional elements of Table 2 for ground faults along the line shown in Figure 1. The graphs in this figure are arranged from highest to lowest in terms of the complete protection system R_F coverage.



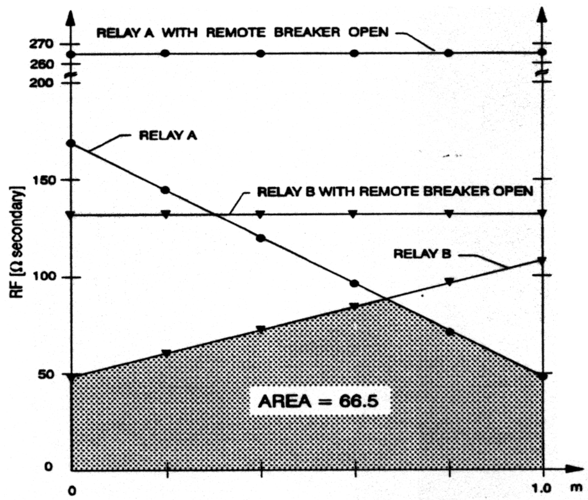
2a: Relay A = Relay B = 321



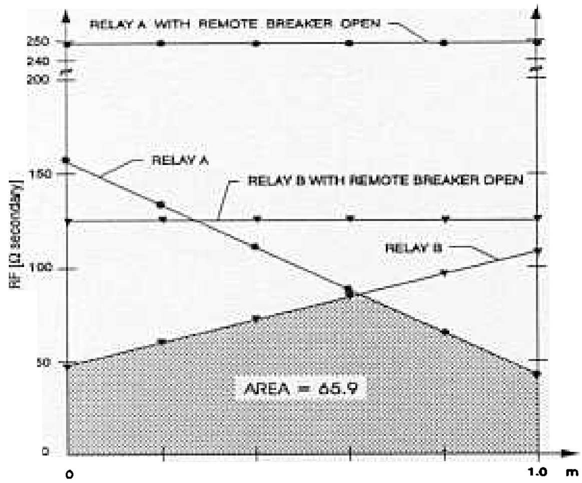
2b: Relay A = 321, Relay B = T32V 221H



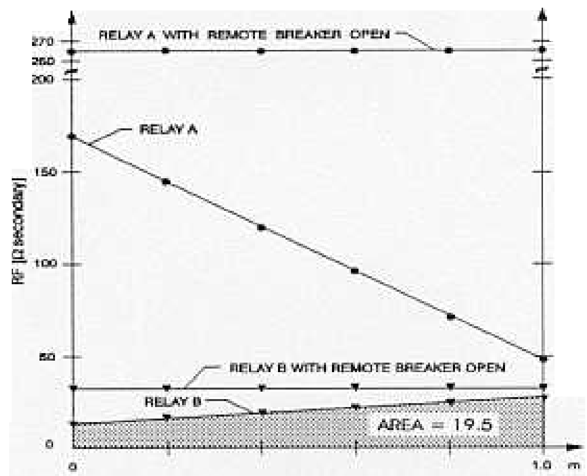
2c: Relay A = Relay B = 221H w/T32V



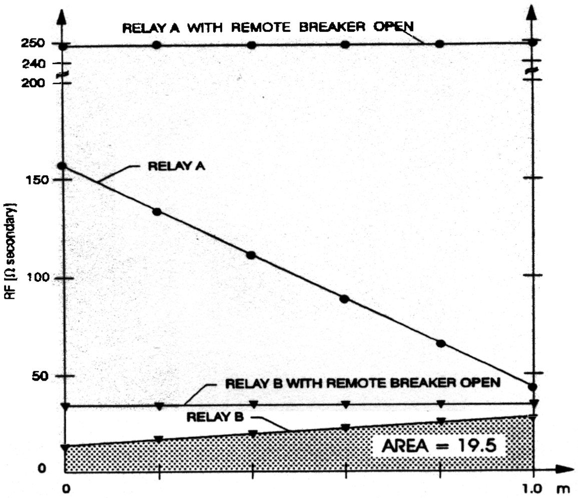
2d: Relay A = 321, Relay B = IRC



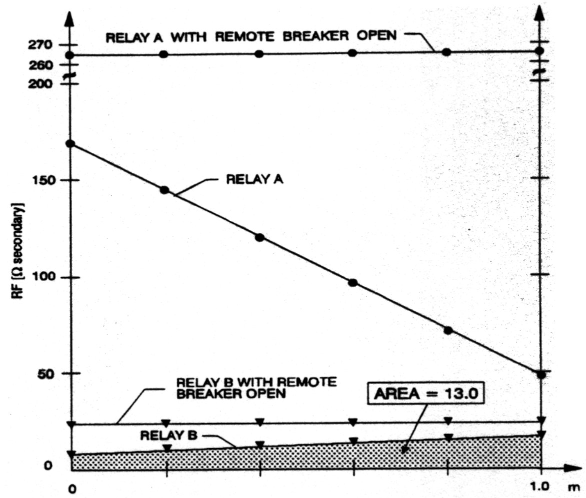
2e: Relay A = T32V 221H, Relay B = IRC



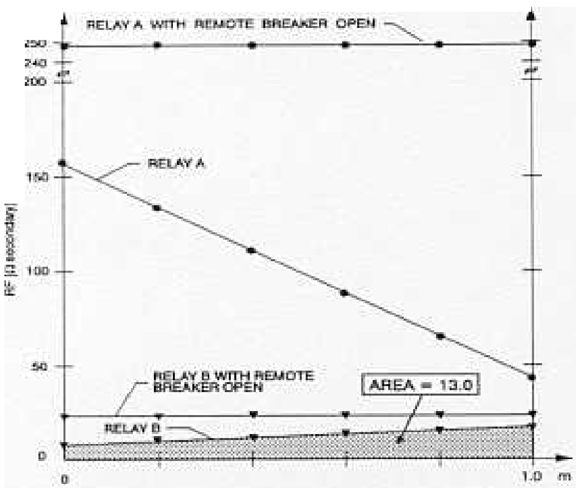
2f: Relay A = 321, Relay B = IRP



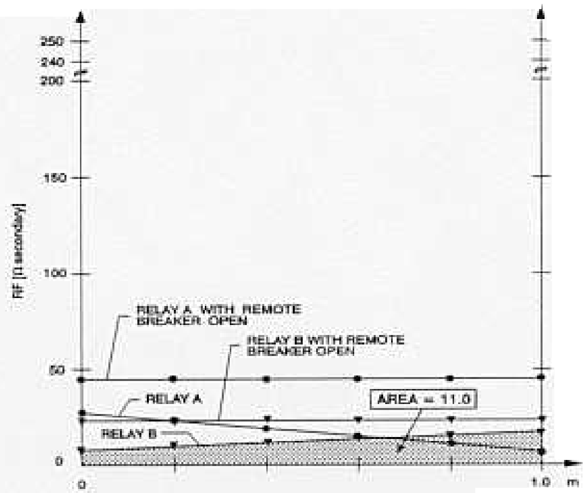
2g: Relay A = T32V 221H, Relay B = IRP



2h: Relay A = 321, Relay B = X



2i: Relay A = T32V 221H, Relay B = X



2j: Relay A = Relay B = X

Figure 2a - 2j: R_F Coverage Limitations Depend on Directional Element Sensitivity

The graphs in Figure 2 show clear differences in R_F coverage for various directional elements. Those relays with higher R_F coverage increase the dependability of the protection at that terminal. If the combination of relays improves R_F coverage (as indicated by a larger shaded area on the graphs), then the protection scheme dependability is increased. Figure 3 shows the area of the polygon formed by the R_F coverage curves for each pair of directional elements.

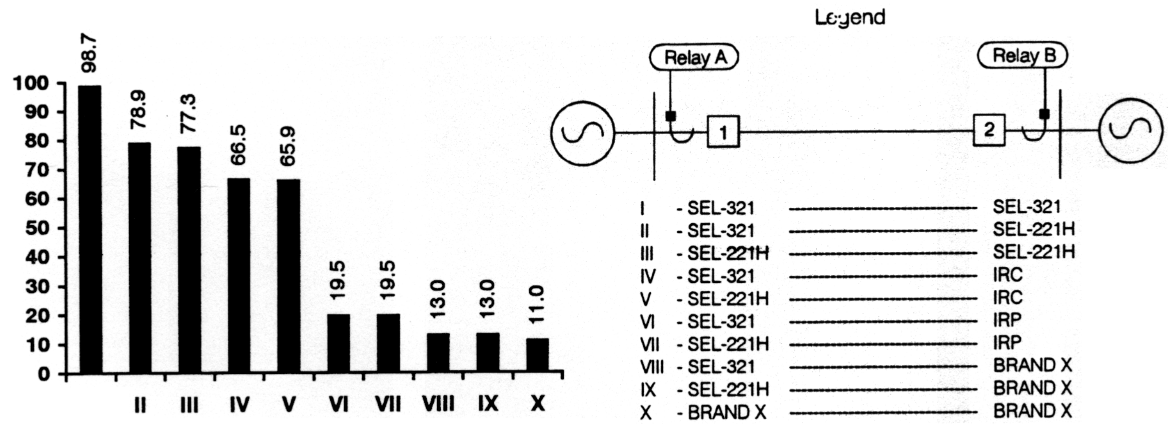


Figure 3: System R_F Coverage for Ten Relay Pairs

Figure 2.h. shows a large directional element sensitivity mismatch. The protection system R_F coverage is restricted by Directional Element 1 at Relay B for all fault locations. The maximum R_F sensed by Relay A is 48 Ω for a ground fault at the remote terminal, while the maximum R_F detectable by Relay B for the same fault location is only 18 Ω. Assume an in-section ground fault close to Bus R and that this fault has R_F = 25 Ω. Only Relay A senses this fault. Next, assume Relay A gives a time-delayed trip. Even without the infeed from Source S, Relay B still cannot sense this fault!

Directional Element Sensitivities and Communication Schemes

This mismatch of directional element sensitivities also causes difficulties in communication-assisted tripping schemes.

Directional Comparison Block (DCB) Scheme Concerns

For security against tripping for out-of-section faults, the reverse-looking protection must sense all faults that are detectable by the remote terminal overreaching elements. However, as the graphs in Figures 2.f through 2.i suggest, there can be out-of-section high-R_F ground faults near the less-sensitive directional element terminal, when the remote terminal senses the fault as forward and the local terminal fails to make a directional declaration. Assuming directional carrier start is used, the remote terminal undesirably trips after its carrier coordination timer expires. If nondirectional carrier start is used, then this is not a concern. Here are some out-of-section fault security solutions where directional carrier start is desired:

1. Set the overreaching directional ground overcurrent element pickup thresholds no more sensitive than that of the directional element sensitivity at the remote terminal (this assumes the reverse-looking, directionally-controlled overcurrent elements have the same or lower pickup threshold as the overreaching elements of the remote terminal). These overreaching element thresholds should be set to some multiple between 1 and 1.5 times the remote terminal directional element sensitivity limit.

   The penalty for this type of security measure is less R_F coverage for internal faults.

2. Use relays at both line ends that have the same sensitivity.

Next, consider an in-section ground fault near the same less-sensitive directional element terminal, and assume non-directional carrier starting elements are used. If the less-sensitive terminal again fails to make a directional declaration, neither terminal trips high-speed because the forward directional elements never pick up to stop carrier at the less sensitive terminal. Solution 2 above resolves this problem.

Permissive Overreaching Transfer Trip (POTT) Scheme Concerns

The dependability of the POTT scheme depends on both relays at either line end sensing all in-section faults simultaneously. If either terminal fails to sense an internal fault, while the other terminal does, then high-speed tripping is defeated. The penalty for using a directional element with less sensitivity at one terminal is less high-speed R_F coverage for internal faults and time-delayed tripping for higher R_F faults.

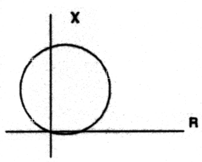
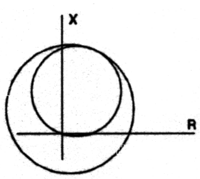
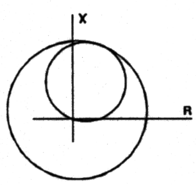
Ground Distance Element Sensitivities

Two commonly used ground distance characteristics are mho and quadrilateral. The mho characteristic is a circle, while the quadrilateral is a polygon on the impedance plane. What factors affect the R_F coverage capabilities of these distance elements?

Mho Ground Distance Elements

Ground mho elements compare the angle between $(Z \cdot I - V)$ and V_p where there are many choices for the polarizing voltage, V_p. Table 3 reviews some of the choices.

Table 3: Mho Element Polarizing Choices

Operating	Polarizing	Characteristic	General Comments
$[Z_{L1} \cdot (I) - V_A]$	V_A (self pol.)		• No expansion. • Unreliable for zero-voltage single-line-ground faults. • Requires directional element.
$[Z_{L1} \cdot (I) - V_A]$	$j \cdot V_{BC}$ (cross pol.)		• Good expansion. • Reliable operation for zero-voltage single-line-ground faults. • Requires directional element. • Single-pole trip applications require study for pole-open security.
$[Z_{L1} \cdot (I) - V_A]$	V_{a1mem} (pos.-seq. mem. pol.)		• Greatest expansion. • Reliable operation for zero-voltage ground faults. • Requires directional element. • Best single-pole trip security.

where

I	$\equiv I_A + k \cdot I_R$	V_{BC}	$\equiv V_B - V_C$
I_A	$\equiv$ A-phase current	I_R	$\equiv$ Residual current $(I_A + I_B + I_C)$
V_A	$\equiv$ A-phase voltage	k	$\equiv (Z_{L0} - Z_{L1})/(3 \cdot Z_{L1})$
Z_{L1}	$\equiv$ Pos.-seq. line impedance	Z_{L0}	$\equiv$ Zero-seq. line impedance

Of the types shown, the positive-sequence memory-polarized elements have:

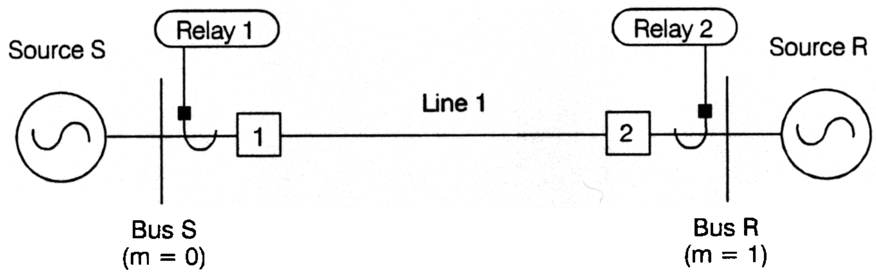
- The greatest amount of expansion for improved R_F coverage. These elements always expand back to the source.

  A common polarizing reference for all six distance-measuring loops. This is important for single-pole tripping during a pole-open period in single-pole trip applications.

Positive-Sequence Polarized Mho Ground Distance Expansion

The amount of expansion that a mho ground distance element experiences for a forward fault depends on the magnitude of the source behind the relay. The weaker the source, the greater the expansion, once the strong remote source clears. Increased R_F coverage is realized when the protected line is radial.

Table 4 summarizes the R_F coverage capability of a Zone 1 positive-sequence memory-polarized mho ground distance element at Relay 1 of Figure 4 for ground faults at $m = 0$, where m is the per-unit distance from Bus S. For each case, the Zone 1 reach is set for $0.8 \cdot Z_{L1}$. Table 4 shows three different local source strengths.



Source S

Strong:	ZS1=2Ω ∠90°	ZS0=6Ω ∠90°
Medium:	ZS1=7.5Ω ∠90°	ZS0=22.5Ω ∠90°
Weak:	ZS1=50Ω ∠90°	ZS0=150Ω ∠90°

Line 1

ZL1=2.5Ω ∠90°
ZL0=7.5Ω ∠90°

Source R

ZR1=2.5Ω ∠90°
ZL1=7.5Ω ∠90°

Figure 4: Single Line Diagram of Three Example Systems

Table 4: Mho Ground Distance R_F Coverage for Internal AG Faults at Bus S, by Relay 1

Source S Strength	SIR[1]	With Infeed (Remote Breaker Closed) $R_{F,\,MAXIMUM}$	Radial (Remote Breaker Open) $R_{F,\,MAXIMUM}$
Strong	1.00	2.12 Ω	3.40 Ω
Medium	3.75	2.10 Ω	6.45 Ω
Weak	20.00	1.10 Ω	16.50 Ω

[1] SIR ≡ Source Impedance Ratio = Z_{S1}/(Zone Reach)

From Table 4, mho expansion improves R_F coverage (because the detectable R_F is greater than 0 Ω). However, this R_F coverage benefit is reduced by infeed if the remote source remains strong. To see this, compare the R_F coverages of infeed verses radial. In all cases, the R_F coverage greatly improves when the remote source clears.

Quadrilateral Ground Distance Elements

The quadrilateral characteristic requires four elements:

- Reactance (top line)
- Positive and negative resistance (sides)
- Directional (bottom)

Reference [2] describes the inputs to a quadrilateral ground distance element.

Again, look at the R_F coverage for the three systems shown in Figure 4, but this time, for a Zone 1 quadrilateral ground distance element.

Table 5 summarizes the R_F coverage of the quadrilateral ground distance element described in [2] for ground faults placed at m = 0 and 0.8. The reactance reach is set to $0.8 \cdot Z_{L1}$, and the resistive reaches to ±50 Ω.

Table 5: Relay 1 Quadrilateral Ground Distance R_F Coverage for Bus S Internal AG Faults

Source S Strength	SIR	m =	Remote Breaker Closed $R_{F,MAXIMUM}$	Remote Breaker Open $R_{F,MAXIMUM}$
Strong	1.00	0.0	31.80 Ω	50.0 Ω
Medium	3.75	0.0	16.00 Ω	50.0 Ω
Weak	20.00	0.0	3.30 Ω	50.0 Ω
Strong	1.00	0.8	13.70 Ω	50.0 Ω
Medium	3.75	0.8	6.83 Ω	50.0 Ω
Weak	20.00	0.8	1.40 Ω	50.0 Ω

The quadrilateral ground distance element provides more R_F coverage, as compared to the expanded mho element. The R_F coverage of the mho and the quadrilateral elements is significantly reduced by remote source infeed. The quadrilateral element most affected is the resistance element, as would be expected. Once the remote source infeed is removed, the quadrilateral resistance element can easily measure large values of R_F.

LIMITS TO SENSITIVITY CAUSED BY INSTRUMENT TRANSFORMERS AND THEIR CONNECTIONS

Directional relays require accurate voltage and current inputs from the instrument transformer to achieve the high R_F coverages noted earlier.

Voltage Transformer (VT) Accuracies

Higher accuracy VTs reduce standing voltages (sequence voltages measured during non-fault, line-energized conditions) and improve R_F coverage. Compare the performance of two possible classes of VTs: Class 1 and Class 2. Table 6 shows that Class 1 errors are half that of Class 2 errors.

Table 6: Class 1 and 2 Maximum Magnitude and Phase Angle Errors

VT Class	Maximum Magnitude Error[1], δM	Maximum Phase Angle Error, $\delta\Theta$
Class 1	±1%	±40 MOA[2] (±0.67°)
Class 2	±2%	±80 MOA[2] (±1.33°)

This error is specified for $5\% \le V_{measured} \le 100\%$ with W, X, and Y burdens for Class 1, and Z burden for Class 2. Reference [3] further defines these burdens.

MOA is the abbreviation for Minutes of Angle. 60 MOA = 1°.

VT Magnitude and Angle Errors Create Standing Voltages

Tables 7 and 8 show the resulting standing V_{A2} and V_{A0} voltages for Class 1 and Class 2 VTs with a ratio error and an angle error from a single phase. The assumed ideal phase voltage magnitude is 66.4 V, and all phase voltages are separated by 120°.

Table 7: Standing Sequence Voltages Present for VT Ratio Errors

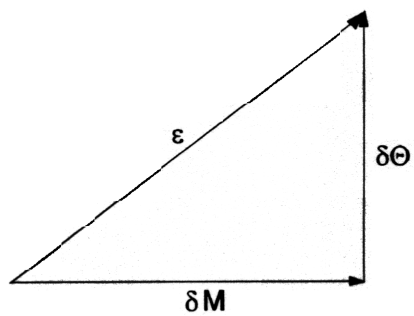
δM	$\delta\Theta$	$V_{A2}, V_{A0, Stand}$
-2%	0	0.44 V $\angle$ 180°
-1%	0	0.22 V $\angle$ 180°
0%	0	0.00 V $\angle$ 0.00°
+1%	0	0.22 V $\angle$ 0.00°
+2%	0	0.44 V $\angle$ 0.00°

Table 8: Standing Voltages as a Result of VT Angle Errors

δM	$\delta\Theta$	$V_{A0}, V_{A2, Stand}$
0	-1.33°	1.54 V $\angle$ -90°
0	-0.66°	0.76 V $\angle$ -90°
0	0.00°	0.00 V $\angle$ 0.00°
0	+0.66°	0.76 V $\angle$ +90°
0	+1.33°	1.54 V $\angle$ +90°

Each of the three VTs can have a plus or minus magnitude and/or a phase angle error. The effect of any error is to produce a standing V_{A2} or V_{A0}, even on a perfectly balanced system. The magnitude and phase angle of this standing voltage is dependent on the individual VTs and possibly their connected burdens. The standing voltage error has different effects on different faults, with different R_F on different phases.

Here is an easy way of looking at the errors shown in Tables 7 and 8. Calculate the error voltage ε, which results from the ratio and phase angle errors using the equation shown in Figure 5.



$$\varepsilon = \sqrt{(\text{magnitude error})^2 + (\text{angle error})^2}$$
$$= \sqrt{(\delta M)^2 + (\delta\Theta)^2}$$

Figure 5: ε is a Starting Point for Calculating R_F Limitations Due to VT Errors

For reliable operation for all fault types, the fault must generate V_{A2} or V_{A0} greater than two or three times that of ε. This ensures that the fault generated V_{A2} and V_{A0} overwhelms the standing voltages.

Calculate ε for the Class 1 VT using the data from Tables 7 and 8.

$$\varepsilon = (0.76\ V^2 + 0.22\ V^2)^{1/2}$$
$$= 0.79\ V$$

Thus, for reliable directional declarations using VTs with maximum error, the ground fault must generate at least 1.58 V of $3 \cdot V_{A2}$ or $3 \cdot V_{A0}$. How much R_F coverage does this requirement allow for an in-section AG fault for the system shown in Figure 1?

AG Fault Near Bus S

Again, using the simplifying assumption listed earlier, consider $|V_{A2,RELAY}|$ at Relay A.

$$V_{A2,RELAY} = \frac{158\ \text{V}}{3}$$

$$(Z_{2EQ} \cdot I_{A2}) \cdot C_{V2}$$

$$(0.82\ \Omega \cdot I_{A2}) \cdot 0.44$$

$$0.82\ \Omega \cdot \frac{66.4\ \text{V}}{3 \cdot R_F} \cdot 0.44$$

Solving for R_F:

$$R_F = 15.07\ \Omega$$

What is $|I_{A2,RELAY}|$ measured at Relay A for $R_F = 15.07\ \Omega$?

$$I_{A2,RELAY} = \frac{66.4\ \text{V}}{3 \cdot R_F} \cdot C_{I2}$$

$$\frac{66.4\ \text{V}}{3 \cdot 15.07\ \Omega} \cdot 0.18$$

$$0.26\ \text{A}$$

Assuming that $|I_{A0,RELAY}|$ approximately equals $|I_{A2,RELAY}|$ at Relay A, setting a directionally-controlled ground overcurrent element no less than 0.79 A ($3 \cdot 0.26$ A) ensures proper directional declarations for maximum VT errors.

The R_F coverage and corresponding $|I_{A2}|$ calculated above are worst case and somewhat discouraging. In reality, these errors can be less. The metering and event reporting features of the microprocessor relays help us understand the standing voltages so we can make the appropriate settings for the directionally-controlled ground overcurrent element pickup settings.

Current Transformer (CT) Accuracies

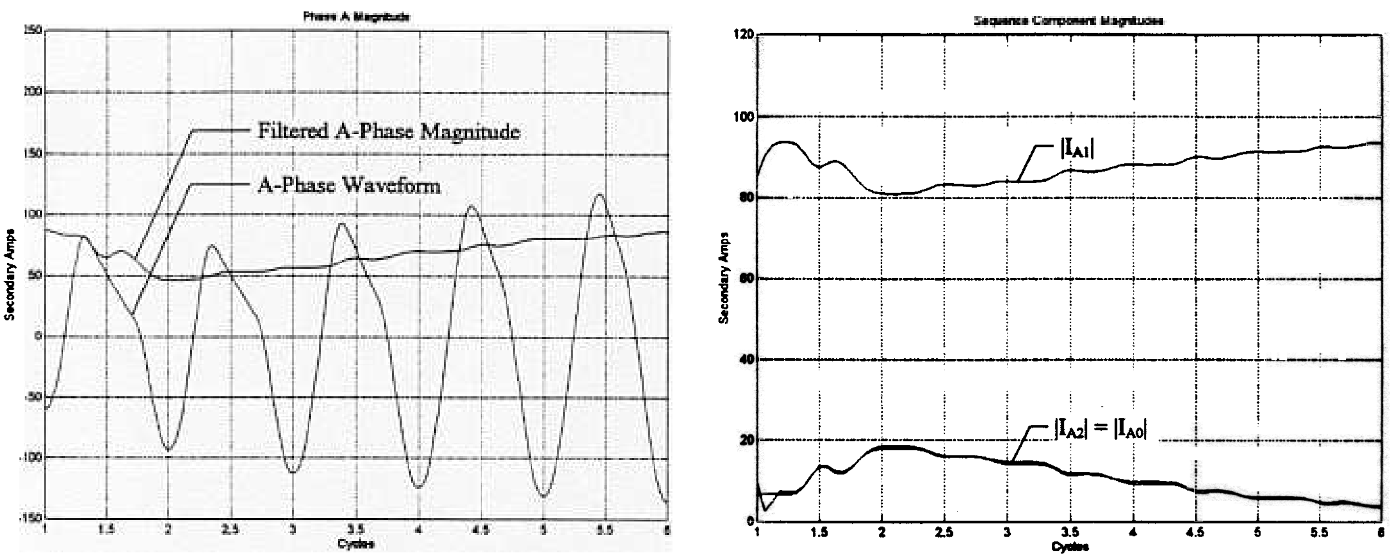
Just as we did for VTs, you could follow a similar process of evaluating sensitivity limitations caused by CT ratio and phase angle errors. The results would show that the higher the accuracy of the CTs used, the higher the R_F coverage. Other considerations for CTs are the selection of the ratio, the C-rating of the device, connected burden, and saturation.

Normally, we do not consider saturation during a discussion of high R_F ground fault detection as the associated primary currents are very small. However, achieving high R_F detection requires very sensitive directional elements. We must ensure that these elements do not pick up and do not misoperate during a close-in, three-phase fault when CT saturation is a concern. The most secure means of achieving this security is to ensure that I_{A2} and I_{A0} or the ratio of I_{A2}/I_{A1} or I_{A0}/I_{A1} are very small. Do this by selecting an adequate C-rating CT and/or reducing the connected burden.

Consider an application that has 12,000 A of primary current for a close-in, three-phase fault and that the A-phase CT has 35% remnant flux. (This assumption ensures that the A-phase CT saturates quicker than the B- and C-phase CTs. If all CTs saturate simultaneously, then no I_{A2} or I_{A0} currents are generated due to CT saturation.) Next assume that the full-winding CT ratio is 600:5, and the connected burden is $0.5\ \Omega \angle 60°$. The ratio for this example is such that the ideal secondary current magnitude is 100 A or 20 times the nominal rating for this fault. The available C-ratings to chose from are C200, C400, and C800.

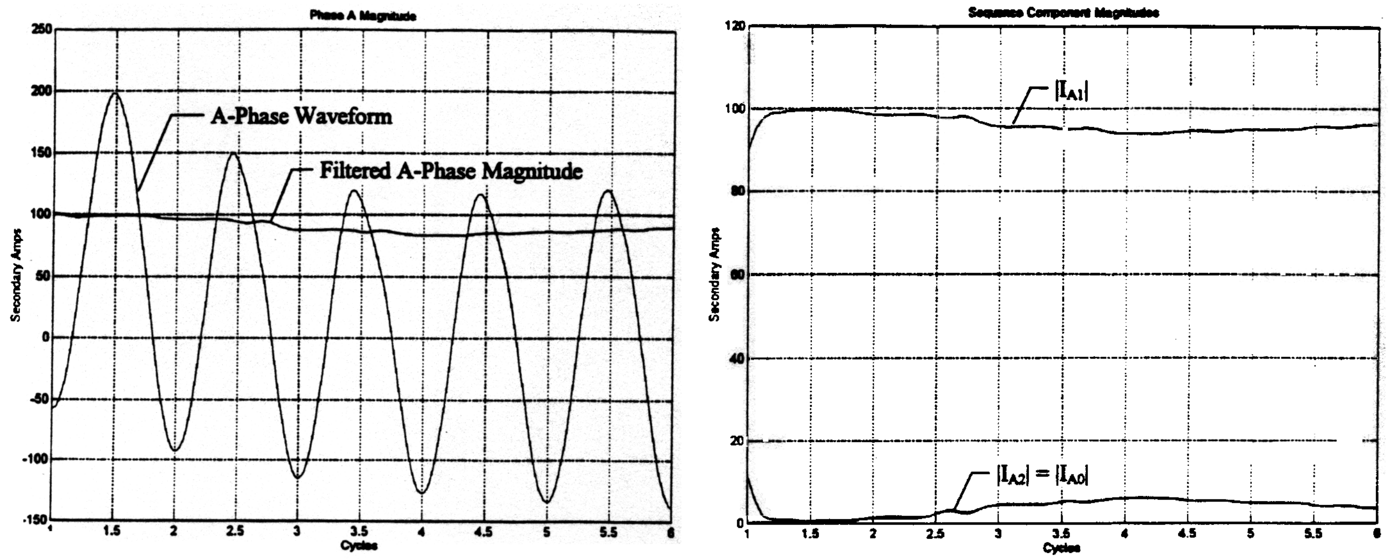
Figure 6.a shows the A-phase secondary current waveform and calculated magnitude for the conditions listed above for a C200 CT. Figure 6.b. shows the resultant I_{A1}, I_{A2} and I_{A0} current magnitudes for the same class CT. In Figure 6.a., the A-phase current magnitude is severely attenuated by the obvious saturation in the waveform. This attenuation on A-phase results in the generation of negative- and zero-sequence secondary currents, which could pick up ground overcurrent elements.

Figure 7 and Figure 8 show the performance of C400 and C800 class CTs for the same conditions as the C200 CT. The higher C-rating CT saturates less, and thereby generates less I_{A2} and I_{A0} currents for the given burden. Reducing the burden and decreasing the secondary current magnitudes also reduces saturation, and thereby allows a lower class CT to be used.



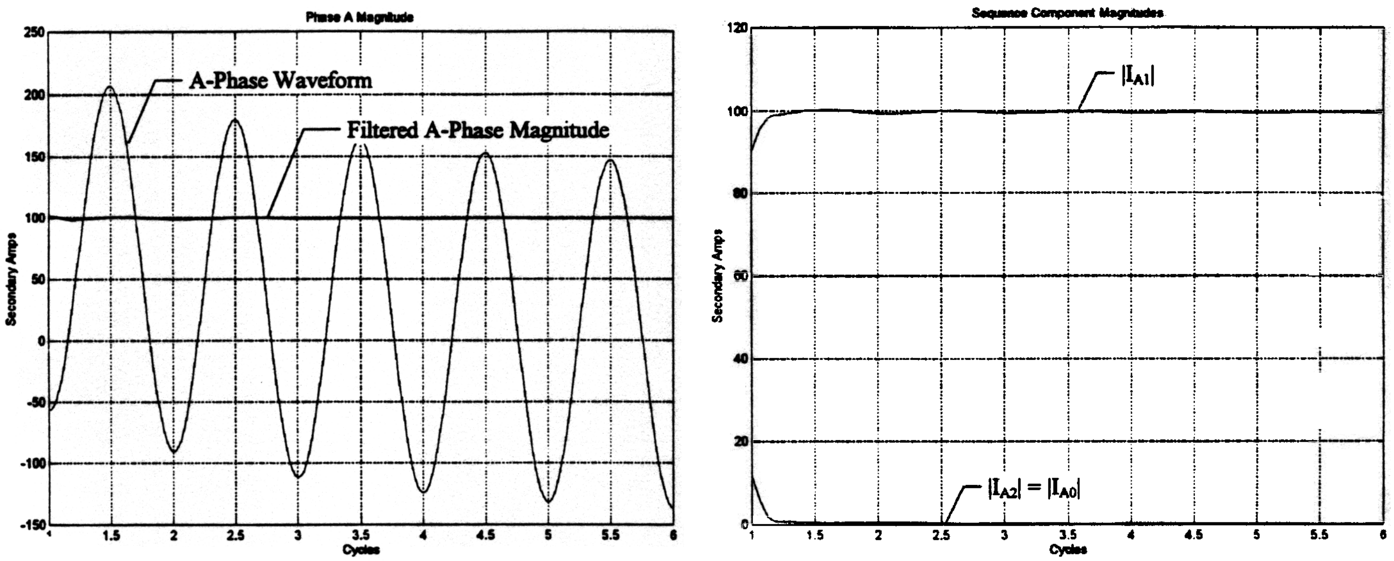
6a: A-Phase Waveform and Magnitude **6b: $|I_{A1}|$, $|I_{A2}|$ and $|I_{A0}|$**

Figure 6a - 6b: C200 CT Saturation Generates Large I_{A2} and I_{A0} Currents for a Three-Phase Fault



7a: A-Phase Waveform and Magnitude 7b: $|I_{A1}|$, $|I_{A2}|$ and $|I_{A0}|$

Figure 7a - 7b: C400 CT Produces Less I_{A2} and I_{A0} Currents Than a C200 CT for the Three-Phase Fault Due to Less Saturation



8a: A-Phase Waveform and Magnitude 8b: $|I_{A1}|$, $|I_{A2}|$ and $|I_{A0}|$

Figure 8a - 8b: C800 CT Generates Trivial I_{A2} and I_{A0} Currents

CT and VT Connection Errors Affect Directional Element Performance

In addition to requiring accurate VTs and CTs, directional relays (like all relays) require proper wiring. The following two real-world examples illustrate how simple wiring errors can affect any directional relay decision.

Do Not Ground VTs in Two Locations

VTs must be grounded in one location only. Figure 9 illustrates the voltage drops present when the VTs are grounded at the VT and again at the relay location.

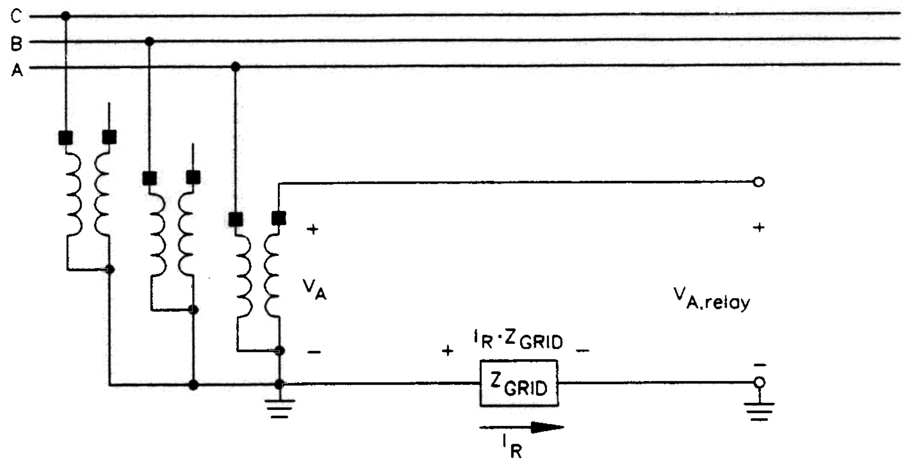


Figure 9: Grounding VTs Twice Introduces an Unwanted $I_R \cdot Z_{GRID}$ Voltage Drop

The voltage drop $I_R \cdot Z_{GRID}$ is present in all phase voltages when the VTs are grounded as shown in Figure 9 (Z_{GRID} is the ground grid impedance, and I_R is the current flowing through the ground grid). For this multiple VT ground situation, the phase voltages delivered to the relay are:

$$V_{A,relay} = V_A + I_R \cdot Z_{GRID}$$

$$V_{B,relay} = V_B + I_R \cdot Z_{GRID}$$

$$V_{C,relay} = V_C + I_R \cdot Z_{GRID}$$

How do the $I_R \cdot Z_{GRID}$ voltage drops affect the relay calculated zero-sequence quantities?

$$\begin{aligned} V_{A0,relay} &= \tfrac{1}{3} \cdot \left(V_{A,relay} + V_{B,relay} + V_{C,relay}\right) \\ &= \tfrac{1}{3} \cdot \left(V_A + I_R \cdot Z_{GRID} + V_B + I_R \cdot Z_{GRID} + V_C + I_R \cdot Z_{GRID}\right) \\ &= \tfrac{1}{3} \cdot \left(V_A + V_B + V_C\right) + \left(I_R \cdot Z_{GRID}\right) \\ &= V_{A0} + I_R \cdot Z_{GRID} \end{aligned}$$

From these calculations, $I_R \cdot Z_{GRID}$ directly affects the zero-sequence voltage measurements. If Z_{GRID} is large, this error could be substantial. The amount of error depends on $|Z_{GRID}|$ and I_R.

How do the $I_R \cdot Z_{GRID}$ voltage drops affect the relay calculated negative-sequence quantities?

$$\begin{aligned} V_{A2,relay} &= \tfrac{1}{3} \cdot \left(V_{A,relay} + a^2 \cdot V_{B,relay} + a \cdot V_{C,relay}\right) \\ &= \tfrac{1}{3} \cdot \left[\left(V_A + I_R \cdot Z_{GRID}\right) + a^2 \cdot \left(V_B + I_R \cdot Z_{GRID}\right) + a^2 \cdot \left(V_C + I_R \cdot Z_{GRID}\right)\right] \end{aligned}$$

$$= \frac{1}{3}\cdot\left[\left(V_A + a^2 \cdot V_B + a \cdot V_C\right) + I_R \cdot Z_{GRID} \cdot \left(1 + a^2 + a\right)\right]$$

$$= V_{A2} \qquad \text{since } \left(1 + a^2 + a\right) = 0$$

From these calculations, grounding the VTs twice does not affect the negative-sequence calculations. However, this is not an endorsement of grounding VTs twice.

Missing Current Transformer Neutral Wires Void Ground Protection

Figure 10 shows an actual accidental miswiring of the CT neutral wire circuit: the neutral return from the relay to the CTs is omitted. The information contained in the microprocessor relay event report led the protection engineer to discover the missing wire. On May 5, 1995, the transmission line experienced two faults. The first fault location read 36.19 miles, while the second event displayed a fault location of 11.93 miles. The initial fault was a phase-phase fault, while the second fault was C-ground. These two faults were separated by 0.508 seconds. The fault locations were believable as the line length is 42.5 miles. Were there two different faults at different locations so close together in time?

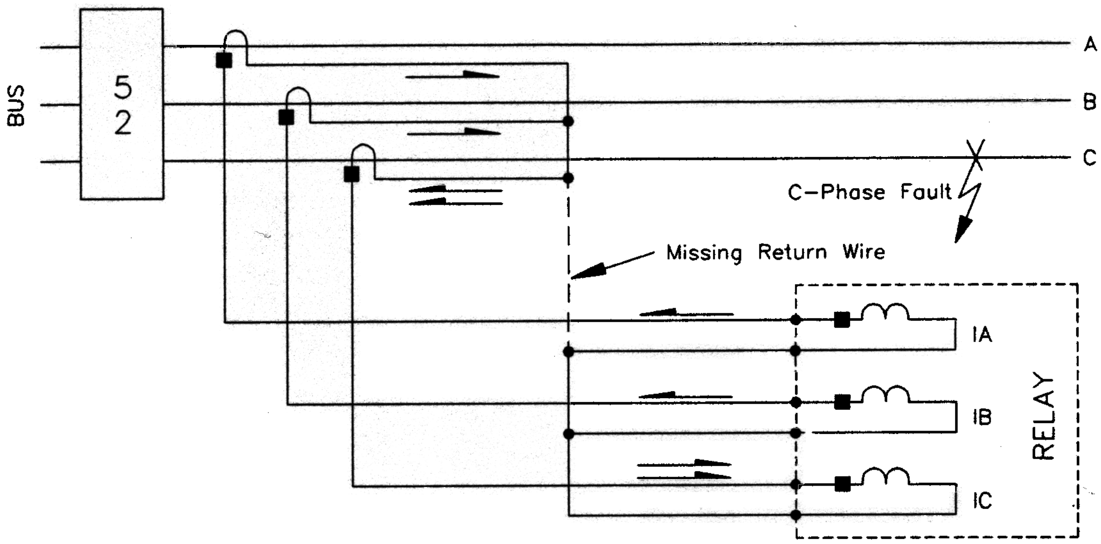


Figure 10: Missing Current Neutral Wiring Diagram

The second event looked suspicious because:

1. There was fault current in all phases, yet only one phase voltage was somewhat reduced.
2. The phase angle relationships of the currents appeared as though the system was ungrounded, yet the engineer knew the system was solidly grounded.

The event report of the microprocessor relay included the following phase voltages and currents:

V_A	$= 68.1\ V_{SEC} \angle 0.0°$	I_A	$= 3.1\ A_{SEC} \angle -107.3°$
V_B	$= 68.9\ V_{SEC} \angle -124.1°$	I_B	$= 3.3\ A_{SEC} \angle -110.7°$
V_C	$= 60.2\ V_{SEC} \angle +115.0°$	I_C	$= 6.4\ V_{SEC} \angle +71.2°$

From this information, we see that the A- and B-phase currents are nearly 180° out-of-phase with the C-phase current. Next calculate the negative- and zero-sequence voltages and currents:

V_{A2} = 4.38 V_{SEC} $\angle$ +74.7° I_{A2} = 3.15 A_{SEC} $\angle$ -169.9°
V_{A0} = 1.58 V_{SEC} $\angle$ -31.8° I_{A0} = 0.03 A_{SEC} $\angle$????°

From the calculated I_{A0}, you can immediately see that the zero-sequence ground directional and overcurrent protection was made inoperative by the missing CT neutral return wire. This point led the engineer to believe there was a problem and that the fault location for the second event was in error. A field check verified that the CT neutral wire was missing. Note that negative-sequence directional and overcurrent elements could properly sense the direction and presence of this ground fault. This is good in that the protection would operate properly, but this is bad because the wiring error could go undetected. It is extremely important to review the analog data contained in the event reports of microprocessor relays every time a fault occurs. Otherwise, problems such as this can go undetected.

LINE ASYMMETRY GENERATES UNBALANCE

Not transposing transmission lines is common practice today. Separate communication and transmission rights-of-way, better communication circuit shielding, and reduced cost are some of the reasons to forgo the cost of fully transposing transmission lines. Eliminating transpositions also means fewer faults. Gross [4] and Lawerence [5] both cited studies that showed that 25 percent of all transmission line outages were associated with faults at transpositions.

While reducing fault exposure, non-transposition of lines results in I_{A2} and I_{A0} current flow for normal load and three-phase faults. The reason is that the self-impedances (Zaa, Zbb, Zcc) are different and mutual-impedances (Zab, Zba, Zac, Zac, Zbc, Zcb) are different. Later, we show that the magnitude of these currents is a percentage of the positive-sequence current flow and depends largely on the line conductor configuration.

While microprocessor relays have the ability to provide greater directional sensitivity than their electromechanical predecessors, we must evaluate the effect of these unbalanced currents on the sensitive directional elements.

Equations 2 through 5 from Gönen [6] represent the self- and mutual-impedances of a three-phase transmission line.

$$Z_{AB,BB,CC} = \left(R_{cond} + 0.00159 \cdot f\right) + j \cdot 0.004657 \cdot \log_{10}\left(\frac{2160}{GMR} \cdot \sqrt{\frac{p}{f}}\right) \Omega / mi \quad (2)$$

$$Z_{AB} = 0.00159 \cdot f + j \cdot 0.004657 \cdot \log_{10}\left(\frac{2160}{d_{AB}} \cdot \sqrt{\frac{p}{f}}\right) \Omega / mi \quad (3)$$

$$Z_{BC} = 0.00159 \cdot f + j \cdot 0.004657 \cdot \log_{10}\left(\frac{2160}{d_{BC}} \cdot \sqrt{\frac{p}{f}}\right) \Omega / mi \quad (4)$$

$$Z_{CA} = 0.00159 \cdot f + j \cdot 0.004657 \cdot \log_{10}\left(\frac{2160}{d_{CA}} \cdot \sqrt{\frac{p}{f}}\right) \Omega / mi \quad (5)$$

where

f	$\equiv$	system frequency [Hz]
R_{cond}	$\equiv$	resistance of the conductor [Ω/mi]
GMR	$\equiv$	geometric mean radius of the conductor [feet]
$d_{AB,BC,CA}$	$\equiv$	distance from conductor A to B, B to C, and C to A, respectively [feet]
p	$\equiv$	earth resistivity [Ωm]

For simplicity, we limit this review to three-phase overhead circuits without ground wires.

Equations (6) through (8) represent the voltage drops along each phase of a three-phase transmission line.

$$V_A = I_A \cdot Z_{AA} + I_B \cdot Z_{AB} + I_C \cdot Z_{AC} \tag{6}$$

$$V_B = I_A \cdot Z_{BA} + I_B \cdot Z_{BB} + I_C \cdot Z_{BC} \tag{7}$$

$$V_C = I_A \cdot Z_{CA} + I_B \cdot Z_{CB} + I_C \cdot Z_{CC} \tag{8}$$

If only positive-sequence current (I_{A1}) flows into the transmission line, then:

$$V_A = I_{A1} \cdot (Z_{AA} + a^2 \cdot Z_{AB} + a \cdot Z_{AC})$$

$$V_B = I_{A1} \cdot (Z_{BA} + a^2 \cdot Z_{BB} + a \cdot Z_{BC})$$

$$V_C = I_{A1} \cdot (Z_{CA} + a^2 \cdot Z_{CB} + a \cdot Z_{CC})$$

The positive-, negative-, and zero-sequence impedances measured due to the flow of positive-sequence current can then be represented as follows:

$$Z_{11} = \frac{V_{A1}}{I_{A1}} = \frac{\frac{1}{3}\cdot\left(V_A + a\cdot V_B + a^2\cdot V_C\right)}{I_{A1}}$$

$$\tfrac{1}{3}\cdot\left[Z_{AA} + Z_{BB} + Z_{CC} - \left(Z_{AB} + Z_{BC} + Z_{AC}\right)\right] \tag{9}$$

$$Z_{21} = \frac{V_{A2}}{I_{A1}} = \frac{\frac{1}{3}\cdot\left(V_A + a^2\cdot V_B + a\cdot V_C\right)}{I_{A1}}$$

$$\tfrac{1}{3}\cdot\left[Z_{AA} + a\cdot Z_{BB} + a^2\cdot Z_{CC} - 2\cdot\left(a^2\cdot Z_{AB} + Z_{BC} + a\cdot Z_{AC}\right)\right] \tag{10}$$

$$Z_{01} = \frac{V_{A0}}{I_{A1}} = \frac{\frac{1}{3}\cdot\left(V_A + V_B + V_C\right)}{I_{A1}}$$

$$\tfrac{1}{3}\cdot\left[Z_{AA} + a^2\cdot Z_{BB} + a\cdot Z_{CC} - \left(a\cdot Z_{AB} + Z_{BC} + a^2\cdot Z_{AC}\right)\right] \tag{11}$$

where

Z_{11}	$\equiv$	Self-impedance as related to a V_{A1} drop due to the I_{A1} causing the drop.
Z_{21}	$\equiv$	Mutual-impedance as related to a V_{A2} drop due to the I_{A1} causing the drop.
Z_{01}	$\equiv$	Mutual-impedance as related to a V_{A0} drop due to the I_{A1} causing the drop.

Hesse [7] showed an excellent approximation of how much negative- and zero-sequence current flows as a percentage of positive-sequence current flow. These approximations use the Z_{21} and Z_{01} quantities calculated above in conjunction with the traditional negative- and zero-sequence line impedances, Z_{22} and Z_{00}, respectively. Equations representing these approximations are:

Calculated I_{a2} due to line asymmetry: $I_{A2} = (| Z_{21} | / | Z_{22} |) \cdot I_{A1}$ (12)

Calculated I_{a0} due to line asymmetry: $I_{A0} = (| Z_{01} | / | Z_{00} |) \cdot I_{A1}$ (13)

Equations 12 and 13 show that I_{A2} and I_{A0} are proportional to I_{A1} and that the proportionality constants are ratios of impedances we can calculate. These constants are:

$$a_2 = |Z_{21}| / |Z_{22}| \quad (14)$$

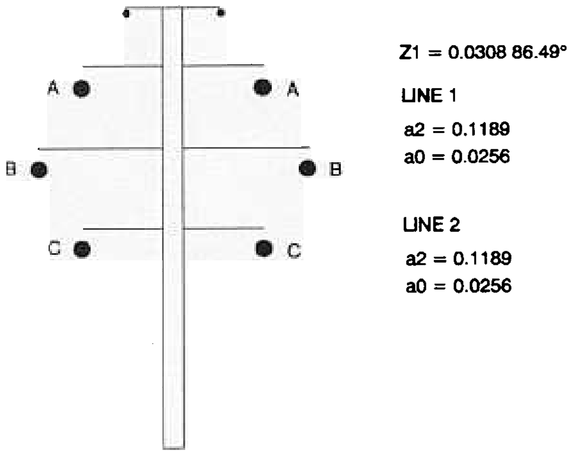
$$a_0 = |Z_{01}| / |Z_{00}| \quad (15)$$

The higher the value of a_2 or a_0, the greater the I_{A2} and I_{A0} current flow during load conditions and three-phase faults. For example, assume $a_2 = a_0 = 0.08$ and that the positive-sequence current flow due to an end-of-line three-phase fault equals 1000 A. For these conditions, the line asymmetry generates 80 A of I_{A2} and I_{A0}. If instead, the positive-sequence current magnitude was 10,000 A, then I_{A2} and I_{A0} would equal 800 A each. In both of these cases, the unbalance current magnitudes are too large to ignore. Next, we show that a_2 and a_0 are not necessarily the same.

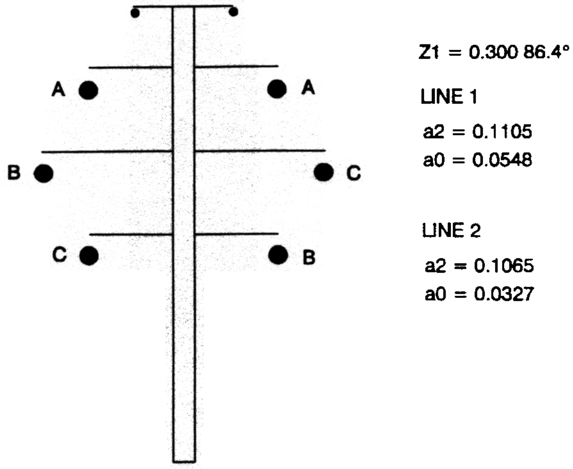
Line Configuration and Phasing - How These Affect a_2 and a_0

The magnitude of a_2 and a_0 is dependent on the line configuration. Figure 11 and Figure 12 show six different phasings each for a horizontal and a vertically configured double-circuit 345 kV transmission line. The source of this information [8] identifies the unbalance load current effects associated with these various phasings and configurations. From the figures, notice the variations of a_2 and a_0 values for each line configuration and phasing.

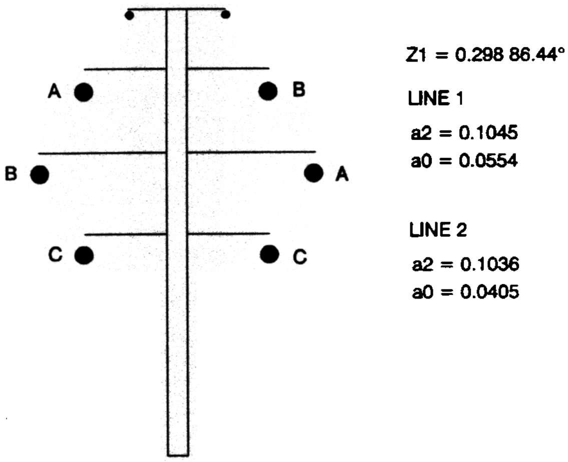
For maximum power transfer, the best phasing for either horizontal or vertical is that which produces the least positive-sequence impedance (Z1). Figure 11.f shows this configuration for the vertical tower configuration. This phasing also results in the lowest a_2 and a_0 ratios. This phasing is very attractive in that it achieves the greatest power transfer capability with the least unbalance, and it generates the least I_{A2} and I_{A0} current magnitudes for three-phase fault conditions.



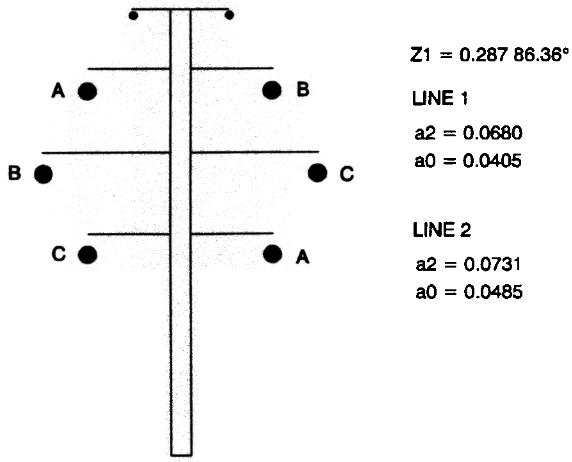
11a: ABC CBA Phasing



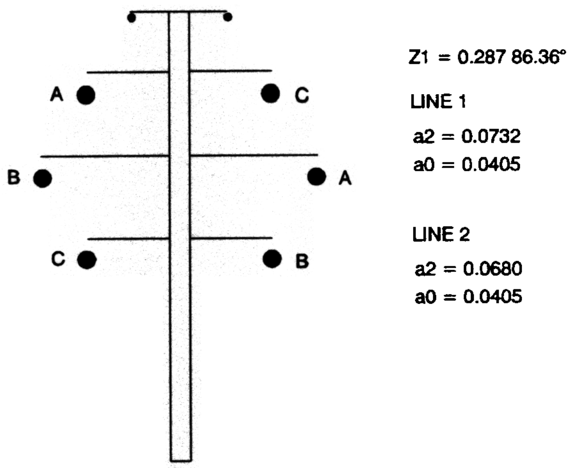
11b: ABC BCA Phasing



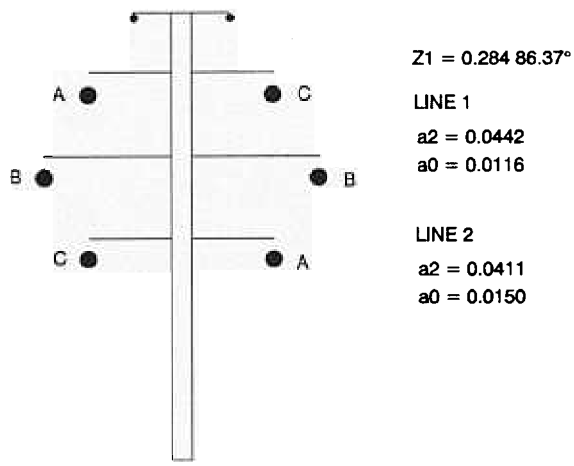
11c: ABC CAB Phasing



11d: ABC ACB Phasing



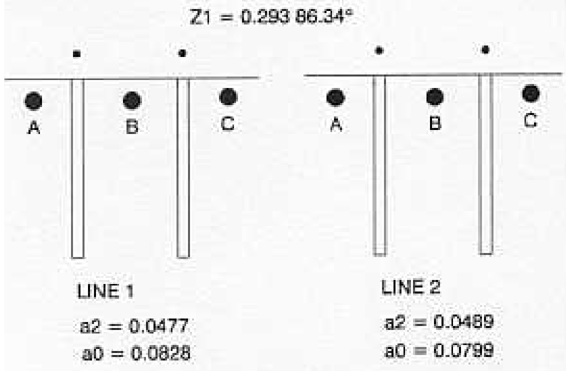
11e: ABC BAC Phasing



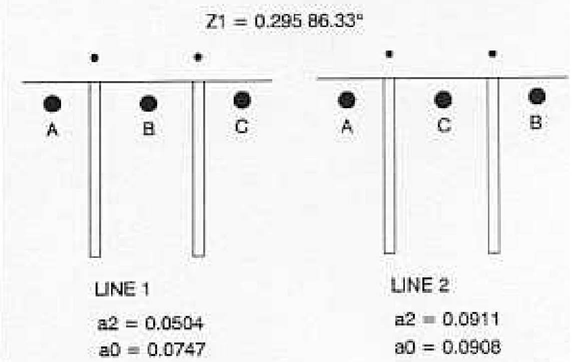
11f: ABC ABC Phasing

Figure 11a - 11f: Vertical 345 kV Tower Configuration and Six Possible Phasing Arrangements

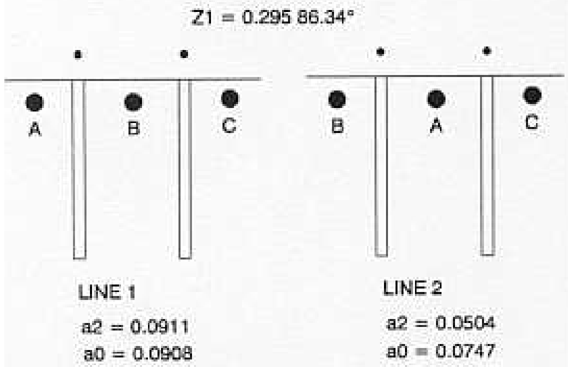
Observations about the horizontal line configuration and phasing are not as clear-cut as for the vertical configuration. For the horizontal configuration, the phasing of Figure 12.a. has the lowest magnitude of Z1 and a_2, but not a_0. Figure 12.e. shows the phasing that produces the lowest a_0 ratio.



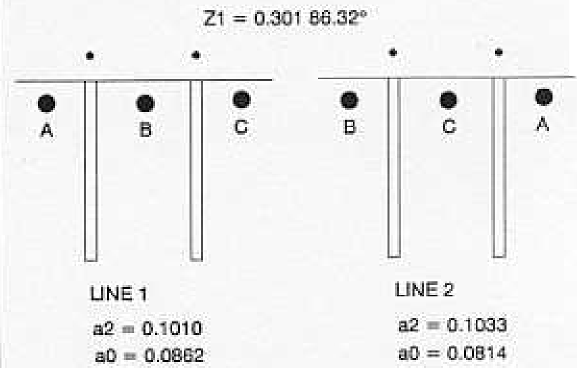
12a: ABC ABC Phasing



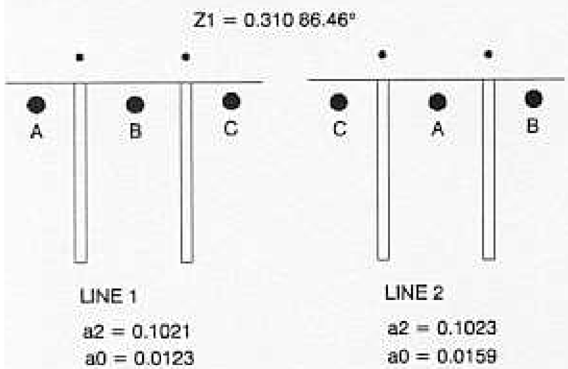
12b: ABC ACB Phasing



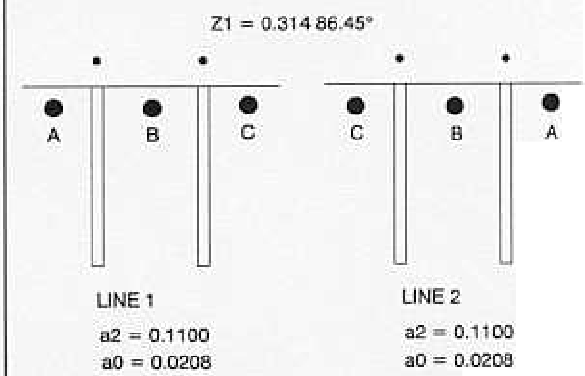
12c: ABC BAC Phasing



12d: ABC BCA Phasing



12e: ABC CAB Phasing



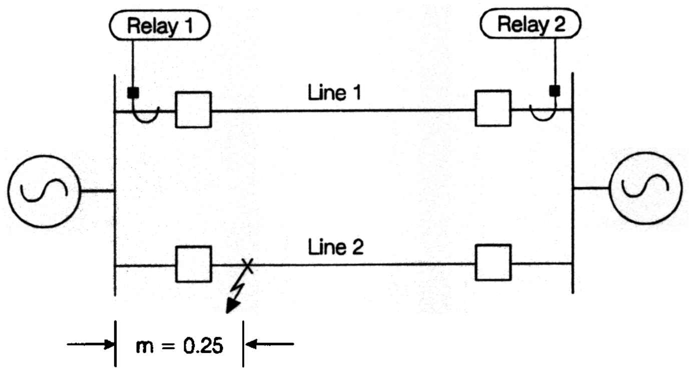
12f: ABC CBA Phasing

Figure 12a - 12f: Horizontal 345 kV Tower Configuration and Six Possible Phasing Arrangements

Line Asymmetry Affects Directional Elements in Communication Schemes

Line asymmetry can adversely affect the ground directional elements in a communication-assisted tripping scheme. The example shown here is a permissive overreaching transfer trip (POTT) scheme.

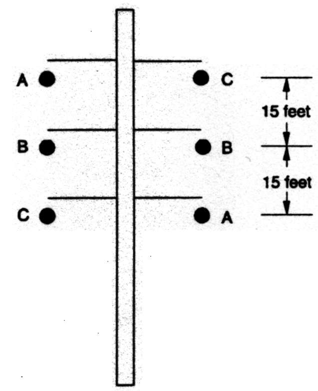
The single-line diagram and tower configuration are shown in Figure 13. The conductors on each circuit are 1033 MCM Ortalan ACSR. Next use Equations 2 through 5 to calculate the self- and mutual-impedances for Lines 1 and 2 to see how much unbalance the line configuration generates. Later, we show that the unbalance can penalize the POTT scheme security for the three-phase fault shown in Figure 13, unless we take precautions during the relay setting procedure.



Source S:
$Z_{S1} = 0.1\ \Omega \angle 87.1°$
$Z_{S0} = 0.1\ \Omega \angle 79.1°$

Source R:
$Z_{R1} = 0.8\ \Omega \angle 84.3°$
$Z_{R0} = 0.3 \angle 84.3°$

13a: Example System Single-Line Diagram



13b: Tower Configuration

Figure 13: Example System Single-Line and Tower Configuration

For the conductor in this example, $R_{cond} = 0.0924\ \Omega/mi$ and the GMR = 0.0402. The self- and mutual-secondary impedances of Line 1 are shown below. The voltage transformer ratio is 2000:1, and the current transformer ratio is 240:1.

$$ZL = \begin{bmatrix} (0.405 + j2.919) & (0.206 + j1.368) & (0.206 + j1.187) \\ (0.206 + j1.368) & (0.405 + j2.919) & (0.206 + j1.368) \\ (0.206 + j1.187) & (0.206 + j1.368) & (0.405 + j2.919) \end{bmatrix}$$

From these self- and mutual-impedances, calculate Z_{11}, Z_{22}, Z_{00}, Z_{21}, Z_{01}. The purpose of performing these calculations is to extract the a_2 and a_0 ratio values. The results are:

$$Z_{11,22} = 1.623 \angle 82.95°$$
$$Z_{00} = 5.594 \angle 81.60°$$
$$Z_{21} = 0.121 \angle 30.0°$$
$$Z_{01} = 0.060 \angle -30.0°$$

$$a_2 = |Z_{21}| / |Z_{22}| = 0.07$$
$$a_0 = |Z_{01}| / |Z_{00}| = 0.01$$

Comparing the a_2 and a_0 values, we see that more negative-sequence than zero-sequence current is generated for three-phase faults. Because the inputs have a greater magnitude, a negative-sequence directional element has a greater likelihood to operate than a zero-sequence directional element.

Table 9 shows the negative- and zero-sequence secondary quantities and the directional element decisions of possible sequence directional elements for Relays 1 and 2.

Table 9: Directional Element Inputs and Outputs for the Example Three-Phase Fault

	Relay 1	Relay 2	Comments
V_{A2}	0.82 V $\angle$ 67.1°	1.0 V $\angle$ -48.8°	Neg.-Seq. Voltage
V_{A0}	0.017 V $\angle$ 138.4°	0.05 V $\angle$ 63°	Zero-Seq. Voltage
I_{A2}	0.61 A $\angle$ 9.6°	0.61 A $\angle$ -170.4°	Neg.-Seq. Current
$3 \cdot I_{A0}$	0.25 A $\angle$ 122.8°	0.25 A $\angle$ -57.2°	Residual Current
I_{A1}	8.56 A $\angle$ -136.94°	8.56 A $\angle$ 43.06°	Positive-Seq. Current
T32Q	0.47 VA (forward declaration)	-0.48 VA (reverse declaration)	Traditional Neg.-Seq. Directional Element Torque
T32V	0.004 VA (no declaration, too small of a torque)	0.013 VA (no declaration, too small of a torque)	Traditional Neg.-Seq. Directional Element Torque
Z2	-1.26 Ω (reverse declaration)	1.41 Ω (forward declaration)	Improved Neg.-Seq. Directional Element
Z0	-0.2 Ω (reverse declaration)	-0.6 Ω (reverse declaration)	Improved Zero-Seq. Directional Element
a_2	0.07	0.07	$\lvert I_{A2} \rvert / \lvert I_{A1} \rvert$
a_0	0.01	0.01	$\lvert I_{A0} \rvert / \lvert I_{A1} \rvert$

How do the directional element outputs shown in Table 9 relate to the security of the Line 1 POTT scheme? For the three-phase fault shown, the overreaching Zone 2 phase distance protection at Relay 2 picks up and keys permission to Relay 1. The reverse looking Zone 3 phase distance protection at Relay 1 also picks up. It is very desirable that no forward-looking protective elements at Relay 1 pick up. For the fault shown, pilot assisted tripping of Relay 2 for the out-of-section fault shown is only blocked if no permissive signal is sent by Relay 1. The security of this scheme depends on the relays at both line ends making correct directional decisions.

From Table 9, we can see that the T32Q calculation for Relay 1 has sufficient torque to make a directional decision and that this directional decision is incorrect. If T32Q is providing the directional control for a sensitively set residual overcurrent element (call this element 67N2), the 67N2 element would key permission to Relay 2. The result of T32Q making an incorrect directional declaration for the fault shown is the tripping of both breakers on Line 1, if the 67N2 element at Relay 1 was set as sensitive as 0.25A.

The T32Q directional elements at Relays 1 and 2 misoperate for the fault shown. The T32V elements at both line ends do not operate as their torques are too small. This relates well with the smaller a_0 value calculated earlier.

The data of Table 9 shows that the impedance-based directional elements also need additional supervision. The Z2 directional elements at either line end make the correct directional declaration without additional supervision, but the Z0 directional element at Relay 2 makes an incorrect directional decision. Next, we discuss supervision methods for these and other directional elements.

Solutions

We have shown that the line asymmetry generates unbalance currents for three-phase faults and that ground directional elements can operate incorrectly. What are the solutions to this security problem, and how does each of these solutions affect sensitivity?

1. Raise the pickup threshold of the directionally-controlled overcurrent elements to a level that is above the corresponding unbalance generated for three-phase faults on an unsymmetrical line.

   Raise the minimum torque thresholds for the ground directional elements so the torque threshold is not exceeded during three-phase faults on an unsymmetrical line.

3. Use a_2 and a_0 ratio factors as relay settings. If the ratio of $|I_{A2}| / |I_{A1}| \geq a_2$, then allow the negative-sequence directional element to give an output. Similarly, if the ratio of $|I_{A0}| / |I_{A1} \geq a_0$, then allow the zero-sequence directional element to give an output.

Solutions 1 and 2 are really equivalent, with Solution 1 being more flexible and easier to coordinate. Fixing the torque threshold at a higher value gives you the necessary security for directional element operation during three-phase faults. The calculated ground directional element torque is $V \cdot I \cdot \cos(\Theta)$, where $\Theta = [\angle - V_{SEQ} - (\angle I_{SEQ} + \angle Z_{SEQ})]$. If we assume $\cos(\Theta) = 1$, we see that raising the minimum V or I required to calculate a directional element torque in effect raises the minimum torque threshold. Earlier, we saw the R_F limitations imposed by requiring too high of a minimum magnitude of V. This leaves raising the I required to calculate a torque. Note that this is equivalent to raising the pickup of the directionally-controlled overcurrent elements. To gain the necessary security for three-phase faults, simply raise the pickup of these overcurrent elements to a level higher than the asymmetry generated unbalance.

Solution 3 describes using the a_2 and a_0 factors calculated earlier as relay settings. Rather than calculating these factors for the purpose of calculating the maximum unbalance current magnitude, simply input these values as relay settings. For a relay that uses these settings, the directional element is not allowed to give an output until the corresponding ratio is exceeded.

How do the R_F coverage offered by Solutions 1, 2, and 3 compare? Figure 14 shows the R_F coverage for four ground directional elements at Relay 1.

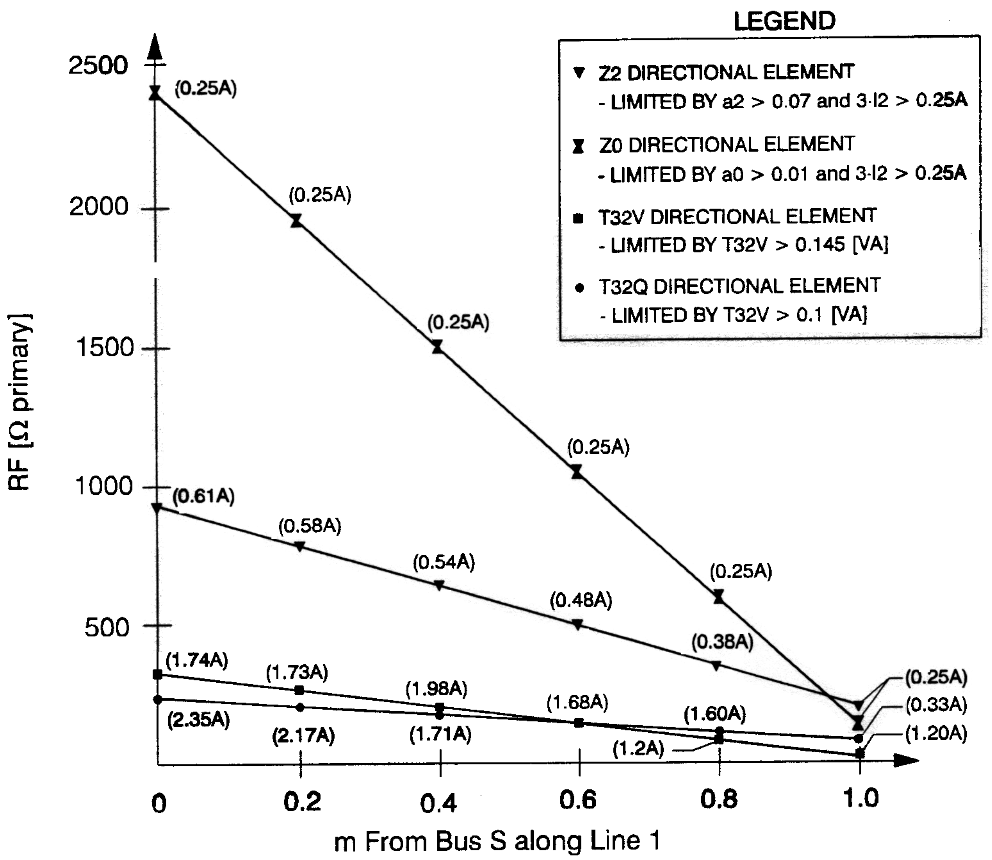


Figure 14: R_F Coverage Comparison of T32Q, T32V, Z2, and Z0 for an Asymmetrical Line

From Figure 14, the Z0 directional element R_F coverage is restricted only by $|3 \cdot I_0| \geq 0.25$ A and $a_0 \geq 0.1$. The Z2 directional element R_F coverage is confined by the a_2 ratio test, while the T32Q and T32V directional elements are limited by their minimum torque thresholds.

Observe from the data in Figure 14 that setting the pickup of any directionally-controlled ground overcurrent element less than that of the residual current level corresponding to the R_F coverage capability of the directional element is only a liability.

Practical Field Checks for Sensitivity and Secure Performance

The following list identifies field checks you can make during installation or routine checks of data captured in relay event reports.

1. **Instrument Transformer Checks:**

   a. Verify the VT and CT ratios against those marked on the instrument nameplate. Use the meter or event reporting feature to validate that the relay is receiving the expected secondary voltages and currents.

   b. Make certain that the VT circuits do not have a VT neutral fuse. Operation of this fuse guarantees VT neutral shift during ground faults. An open neutral denies the relay of zero-sequence voltage. If you find a fuse, replace it with a solid copper bar or jumper around the fuse holder.

c. Verify that the VTs and CTs are grounded in only one place.

d. Verify the proper phase rotation and phasing of the voltage and current circuits. Proper phase rotation and phasing are required for directional elements using negative-sequence quantities.

2. **Standing Voltage and Current Checks**

   Verify the phase balance of the VTs and CTs by measuring the amount of V_{A2}, V_{A0}, I_{A2}, and I_{A0} during normal load conditions. Excessive negative- or zero-sequence quantities suggest excessive instrument transformer error, system unbalance, or load imbalance.

   Insure that ground faults provide two to three times as much unbalance as the standing unbalance by requiring sufficient fault current to "swamp out" the standing unbalance.

3. **Adjacent Station Comparison Checks**

   In new installations, you should validate the metered megawatt and megavar readings by comparing those values against other proven meters in adjacent stations.

   The megawatt and megavar flows as measured at both ends of the line are opposite: one line terminal should measure megawatt flow in (out) and the remote line terminal should measure megawatt flow out (in).

4. **Line Construction Check**

   Earlier in this paper, we showed that various line phasings and configurations cause differing amounts of negative- and zero-sequence current flow for normal load conditions. Determine if relay settings should be desensitized to accommodate unbalance introduced by line unbalance.

5. **Analyze Event Reports**

   Analyze the valuable event report data every time. The information contained in these reports is more valuable than routine maintenance testing. In countless cases, the event report information points to one of the items discussed in this paper. This method of "testing" is far less expensive than that incurred for routine relay testing and may uncover problems that would not be discovered in the traditional testing methods. It is also more interesting and rewarding.

SUMMARY

1. Unbalance throughout the power and protection system limits protection system sensitivity. Not considering these sources of unbalance can cause relay misoperations when relays are set too sensitively. Misoperations include unwanted tripping for out-of-section faults and failure to trip for in-section faults.

2. A relay design that requires a 1 V minimum of V_{A2} (faulted-phase voltage must drop 3 V) has a severely restricted R_F coverage and causes coordination difficulties when used with more sensitive relays.

3. Properly designed quadrilateral ground distance elements can provide more R_F coverage than an expanded mho ground distance element.
4. The sensitivity of ground distance elements is greatly affected by remote infeed.
5. Raising the pickup thresholds of residual overcurrent elements is generally equivalent to increasing the directional element torque threshold as a means of tolerating standing unbalance.
6. The sensitivity of the protective system depends on individual relay sensitivities. Check VA, V, and current limits.
7. Where dissimilar relays are used at either end of the transmission line, you must coordinate the ground relays and consider the internally fixed and settable limits of critical elements.
8. Where directional carrier start is used in DCB applications, you must coordinate the directional element sensitivities at both line ends to ensure security for out-of-section faults.
9. Multiple grounds on VTs and CTs frequently cause significant zero-sequence measurement errors. Verifying that the instrument transformers are grounded in only one place is an easy step toward avoiding serious measurement errors.
10. Ratio and phase angle instrument transformer errors can limit the R_F coverage of directional elements. Knowing these errors is important to making proper ground overcurrent element pickup settings.
11. Unequal CT saturation during three-phase faults generates negative- and zero-sequence currents. Avoid saturation by using CTs with a high C-rating, and minimize cable and relay burdens. Consider putting electromechanical relays on separate CTs to reduce errors on more sensitive microprocessor relays.
12. Unbalances introduced by line asymmetry can cause incorrect directional operations. Set the ground overcurrent element pickup levels above the unbalance, and/or set a negative- or zero-sequence current to positive-sequence current ratio factor to supervise the directional element.
13. Analyze each and every microprocessor relay operation to ensure that the overall protection system is secure and reliable. This step is more important than routine testing of microprocessor relays. Get to the root of every problem, question, and uncertainty. Carefully review even normal looking operations because they often have clues useful in avoiding future trouble.

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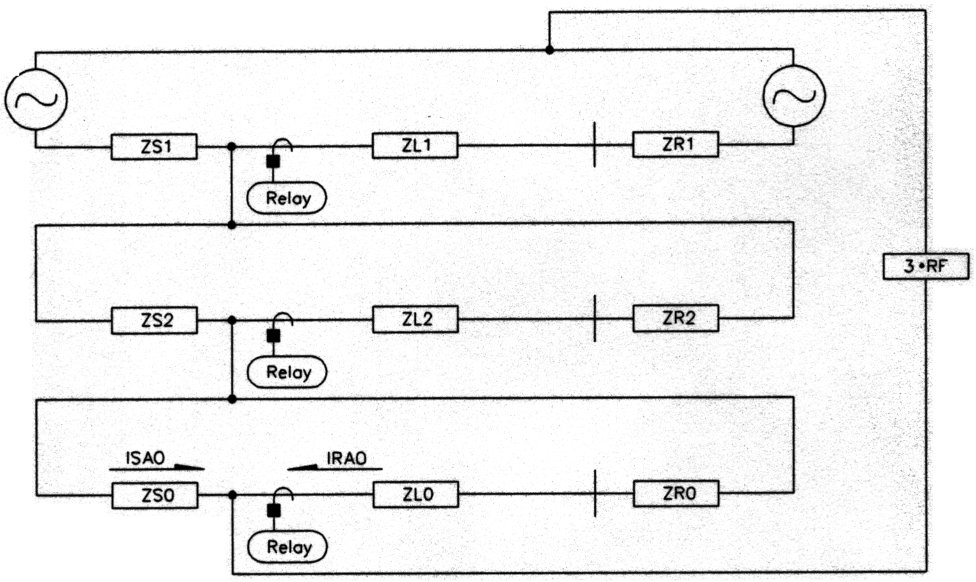
APPENDIX A

Improved Zero-Sequence Voltage-Polarized Directional Element (Patent Pending)

This appendix describes a new zero-sequence voltage-polarized directional element which overcomes dependability and security problems of traditional zero-sequence voltage polarized directional elements.

Figure A1 shows the sequence network connect for a phase-ground fault. The relay shown in the figure is monitoring all sequence currents and voltages. Zero-sequence directional elements use zero-sequence quantities only.



where:

$Z_{S1,R1}$ = positive-sequence local and remote source impedances respectively
$Z_{S2,R1}$ = negative-sequence local and remote source impedances respectively
$Z_{S0,R0}$ = zero-sequence local and remote source impedances respectively
$Z_{L1,L2,L0}$ = positive-, negative, and zero-sequence line impedances respectively
R_F = Fault resistance

Figure A1: Relay Monitors Sequence Quantities

When the zero-sequence source impedance behind the relay terminal is very strong, the zero-sequence voltage (V_{A0}) at the relay can be very low, especially for remote faults.

To overcome low V_{A0} magnitude, we can add a compensating quantity which boosts V_{A0} by $\alpha \cdot Z_{L0} \cdot I_{A0}$. The constant α controls the amount of compensation.

Equation (A1) shows the torque expression for a compensated zero-sequence directional element.

$$T32V = Re[(V_{A0} - \alpha \cdot Z_{L0} \cdot I_{A0}) \cdot (Z_{L0} \cdot I_{A0})^*] \qquad (A1)$$

where:

* indicates complex conjugate

The term $(\alpha \cdot Z_{L0} \cdot I_{A0})$ adds with V_{A0} for forward faults, and subtracts for reverse faults. Setting α too large can make a reverse fault appear forward. This results when $(\alpha \cdot Z_{L0} \cdot I_{A0})$ is greater but opposed to the measured V_{A0} for reverse faults.

Relationship of the Apparent Z_0 to Fault Direction

Figure A1 shows the sequence network for a ground fault at the relay. The relay measures I_{SA0} for forward faults, and $-I_{RA0}$ for reverse faults.

From V_{A0} and I_{A0}, calculate Z_0:

Forward Ground Faults: $Z_0 = -V_{A0}/I_{SA0} = -Z_{S0}$

Reverse Ground Faults: $Z_0 = -V_{A0}/-I_{RA0} = (Z_{L0} + Z_{R0})$

This relationship is shown in Figure A2 for a 90° system.

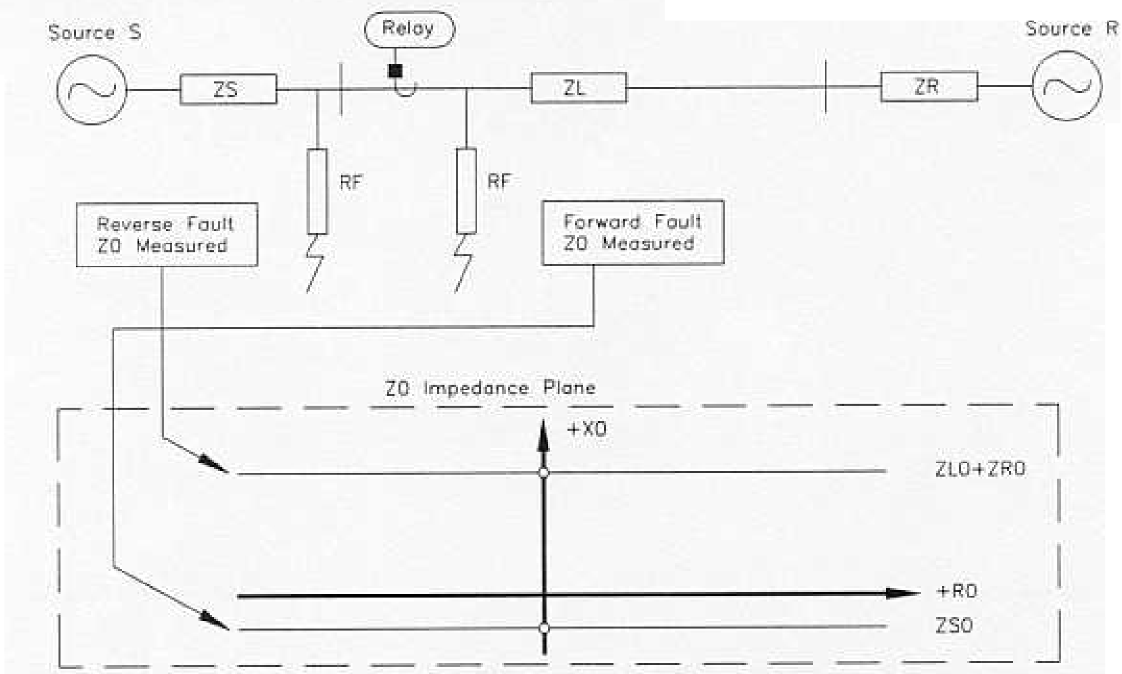


Figure A2: Zero-Sequence Source Impedance Measurement in the Zero-Sequence Plane

For the system in Figure A2, the fault is forward if Z_0 is negative, and reverse if Z_0 is positive.

Zero-Sequence Directional Element Based on Calculating and Testing Z_0

The discussion above shows that calculated Z_0 could be used to determine fault direction.

Recall the compensated directional element equation, T32V:

$$T32V = \mathrm{Re}[(V_{A0} - \alpha \cdot Z_{L0} \cdot I_{A0}) \cdot (Z_{L0} \cdot I_{A0})^*]$$

The forward/reverse balance condition for this element is zero torque. This is:

$$0 = \mathrm{Re}[(V_{A0} - \alpha \cdot Z_{L0} \cdot I_{A0}) \cdot (Z_{L0} \cdot I_{A0})^*]$$

Let $\alpha = z_0$

$Z_{L0} = 1 \angle \Theta$ where Θ is $\angle Z_{L0}$

Substituting,

$$0 = \mathrm{Re}[(V_{A0} - z_0 \angle\Theta \cdot I_{A0}) \cdot (I_{A0} \cdot 1\angle\Theta)^*]$$

Solving for z_0 results in an equation corresponding to the condition of zero-torque:

$$z_0 = \frac{\mathrm{Re}\left[V_{A0} \cdot (I_{A0} \cdot 1\angle\Theta)^*\right]}{\mathrm{Re}\left[\cdot(I_{A0} \cdot 1\angle\Theta) \cdot (I_{A0} \cdot 1\angle\Theta)^*\right]}$$

$$z_0 = \frac{\mathrm{Re}\left[V_{A0} \cdot (I_{A0} \cdot 1\angle\Theta)^*\right]}{|I_{A0}|^2}$$

Recall that the $(\alpha \cdot Z_{L0} \cdot I_{A0})$ term increases the amount of V_{A0} for directional calculations. This is equivalent to increasing the magnitude of the zero-sequence source impedance behind the relay location for forward faults. This same task is accomplished by increasing the forward z_0 threshold.

The criteria for declaring forward and reverse faults are then:

If z_0 < forward threshold, then the fault is forward

z_0 > reverse threshold, then the fault is reverse

The forward threshold must be less than the reverse threshold to avoid any overlap.

The z_0 directional element has all the benefits of both the traditional and the compensated zero-sequence directional element.

References

1. Patent Num. 5365396. Schweitzer Engineering Laboratories, Inc. "Negative-sequence directional element for a relay useful in protecting power transmission lines," 1994-11-15.

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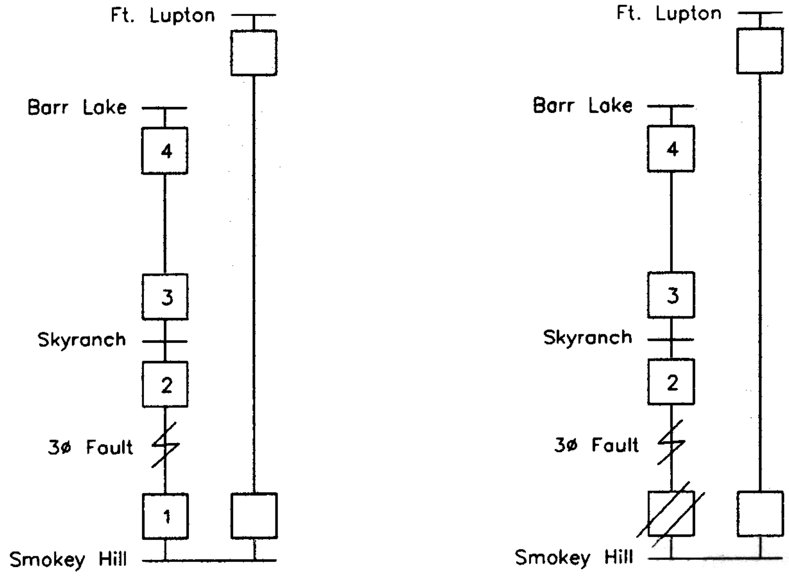
APPENDIX B

On December 20, 1994, Public Service of Colorado experienced a misoperation of the Barr Lake to Skyranch POTT scheme following a line breaker closing test into a three-phase fault on the Skyranch to Smokey Hill 230 kV line. Figure A3.a. shows the system single-line diagram.



A3.a: Initial Fault **A3.b: Line Test**

Figure A3: System Single-Line Diagram for Initial Three-Phase Fault and the Line Test Following the Initial Three-Phase Fault

Sequence of Events

Breakers 1 and 2 cleared the initial three-phase fault shown in Figure A3.a. When Breaker 2 closed to test the line (Figure A3.b. shows the system configuration during the line test), the POTT scheme on the Barr Lake to Skyranch line operated.

The relays at Breakers 3 and 4 captured event reports for this line test and subsequent misoperation. Figure A.4 shows an excerpt from the Skyranch relay.

```
5759 SKYRANCH TO BARR LAKE              Date: 12/20/94     Time: 03:08:48.325

FID=SEL-121G5-R400-V656mptr12sy2-D891110

              Currents                  Voltages       Relays Outputs Inputs
               (amps)                     (kV)
                                                       52265L TCAAAAA DPBD5E
  IPOL     IR      IA      IB      IC      VA      VB      VC  011710 PL1234L TTTC2T
                                                       P3PNNP              A
              •
              •
              •
     0   -270    -147    2235   -2356    -5.0   -11.9     2.3 M4.... ....... ....*.
     0   -212   -2605    1465     936     7.7     6.8    -3.8 M4.... ....... ....*.
     0    260     140   -2209    2326     2.9    11.1     0.5 M4.2P. ..*.... ....*.
     0    229    2601   -1427    -948    -8.3    -9.1     6.0 M4.2P. ..*.... ....*.

     0   -240    -113    2201   -2326     3.2   -11.7     1.1 M4.2P. *.**.*. .*..*.
     0    121   -1978    1272     827    26.0     4.8   -15.5 M4.... *..*.*. .*..*.
     0     -4       8   -1763    1752   -49.3    35.4    -4.1 M4.... *..*.*. .*..*.
     0   -355     770    -732    -393   -31.1   -27.2    54.3 M..... *..*.*. .*..*.

              •
              •
              •
```

Figure A4: Skyranch Relay Event Report Shows 67N2 Element Picked Up When Permissive Trip Signal Present

From Figure A4, notice that the Level 2 overreaching element (67N2) used in the POTT scheme logic is picked up concurrent to the assertion of the permissive trip (PT) input. (The 67N2 element being picked up is shown as a 2 in the 67N column while the PT input assertion is shown by the * symbol in the PT column.) The 67N2 element being picked up while the PT input was asserted generated the undesirable trip.

The protective relay at Barr Lake operated correctly by detecting the forward three-phase fault shown in Figure A3 and keying permissive trip. The preferred action of the protective relay at Skyranch would be to declare this fault as reverse. However, the negative-sequence polarized ground directional element declared the fault direction forward, allowing the 67N2 element to operate. The pickup of the 67N2 element was set to 60A primary.

Non-Transposed Line Generated Unbalance

The 230 kV lines shown in Figure A3 were non-transposed. Thus, from the discussions earlier about non-transposed lines we expect there to be I_{A2} and I_R (= $3 \cdot I_{A0}$) for this three-phase fault. Using the highlighted rows from the event report shown in Figure A4, calculate the a_2 and a_0 values:

$$I_A = (2601 + j140) \text{ A pri.} = 2604.8 \text{ A} \angle 3.1°$$

$$I_B = (-1427 - j2209) \text{ A pri.} = 2629.8 \text{ A} \angle -122.9°$$

$$I_C = (-948 + j2326) \text{ A pri.} = 2511.8 \text{ A} \angle 112.2°$$

Calculate I_{A1}, I_{A2}, and I_{A0} using I_A, I_B, and I_C:

I_{A1} = 2574.4 A

I_{A2} = 171.8 A

I_{A0} = 114.1 A

From these values, we calculate $a_2 = 0.0667$ ($|I_{A2}|/|I_{A1}|$) and $a_0 = 0.0443$ ($|I_{A0}|/|I_{A1}|$). These simple calculations using the event report data show us that every 1000 A of I_{A1} results in 66.7 A of I_{A2} and 132.9 A of I_R.

At the time of this three-phase fault, the 67N2 element pickup at Skyranch was set for 60 A primary (or 0.25 A secondary given the current transformer ratio of 240:1). Thus, the measured I_R current exceeded the 67N2 element pickup threshold during the three-phase fault. Assuming the maximum three-phase reverse fault current magnitude is 2574 A, one solution to this security problem is to raise the pickup of the 67N2 element to some value greater than 1.42 A (2574.4 A · 0.0443) to prevent this element from operating on the unbalance currents generated by the non-transposed the line.

BIOGRAPHY

Jeff Roberts received his BSEE from Washington State University in 1985. He worked for Pacific Gas and Electric Company as a Relay Protection Engineer for over three years. In 1988, he joined Schweitzer Engineering Laboratories, Inc. as an Application Engineer. He now serves as Research Engineering Manager. He has delivered papers at the Western Protective Relay Conference, Texas A&M University, Georgia Tech, and the South African Conference on Power System Protection. He holds multiple patents and has other patents pending. He is also a member of the IEEE.

Edmund O. Schweitzer, III is President of Schweitzer Engineering Laboratories (SEL), Pullman, Washington, U.S.A., a company that designs and manufactures microprocessor-based protective relays for electric power systems. He is also an Adjunct Professor at Washington State University. He received his BSEE from Purdue University in 1968 and MSEE from Purdue University in 1971. He received his Ph.D. from Washington State University in 1977.

Dr. Schweitzer is recognized as a pioneer in digital protection and holds the grade of Fellow in the Institute of Electrical and Electronic Engineers (IEEE), a title bestowed on less than one percent of IEEE members.

He has written dozens of technical papers in the areas of distance relay design, filtering for protective relays, protective relay reliability and testing, fault locating on overhead lines, induction motor protection, directional element design, dynamics of overcurrent elements, and the sensitivity of protective relays.

Dr. Schweitzer holds more than a dozen patents pertaining to electric power system protection, metering, monitoring, and control.

Renu Arora received her BSEE from Washington State University in 1985. She worked for Southern California Edison during 1986-1987. Since April 1987, she has been with Public Service Company of Colorado, where she is currently a System Protection Engineer. She is a Registered Professional Engineer in the State of Colorado. Her work includes design of protection systems for substations, transmission lines, distribution systems, and power generating plants.

Ernest Poggi received his BSEE from the University of Lowell (Lowell Tech. Institute) in 1976. He has been involved in the design and operation of power system substations and system protection equipment for 19 years with Florida Power & Light, Tri-State G&T, and Public Service Company of Colorado, where he is a Registered Professional Engineer in the State of Colorado and has participated in the IEEE subcommittee group on HVDC. He has co-authored and assisted in papers delivered to the Western Protective Relay Conference.