Considerations in Choosing Directional Polarizing Methods for Ground Overcurrent Elements in Line Protection Applications

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1.0 Introduction

In a networked transmission system, ground overcurrent elements can be very difficult to coordinate based on fault magnitude alone. For this reason, directional elements are used to supervise ground overcurrent elements so that they only operate for faults in one direction, either forward or reverse, in order to simplify coordination.

Most ground directional overcurrent relays can be thought of as having two components, a directional component and an overcurrent component. In order for a trip to occur, the magnitude of the operate quantity exceeds the threshold limit for a specific duration and the direction of the fault must be within the operate (trip region) characteristic for a trip decision.

A fixed reference or polarizing source is required to make such a determination, so that some "operate" quantity (e.g., zero sequence line current) can be compared against the fixed reference. The polarizing source should not change direction regardless of fault location.

Some of the reasons for developing this report include:

- Given the potential difficulties in testing transformer neutral current polarizing circuits, some have put forth the idea of discontinuing the use of current polarizing altogether in favor of voltage polarizing, either zero-sequence or negative-sequence.

- Many microprocessor relays offer only negative-sequence polarizing, but there are limitations to the use of this method, especially on long lines.

Besides transformer neutral current and negative-sequence, other polarizing methods are available, including zero sequence voltage, as well as a few lesser known methods. This report describes the different methods and discusses application considerations for each. Recommendations on how to choose the appropriate method are provided, which is the main emphasis of the report.

The appendix includes several examples of situations where a particular polarizing method proved to be inadequate.

2.0 Sequence Network for Ground Faults

Following two figures show the sequence network of the polarizing sources at the relaying terminal for a remote bus ground fault.

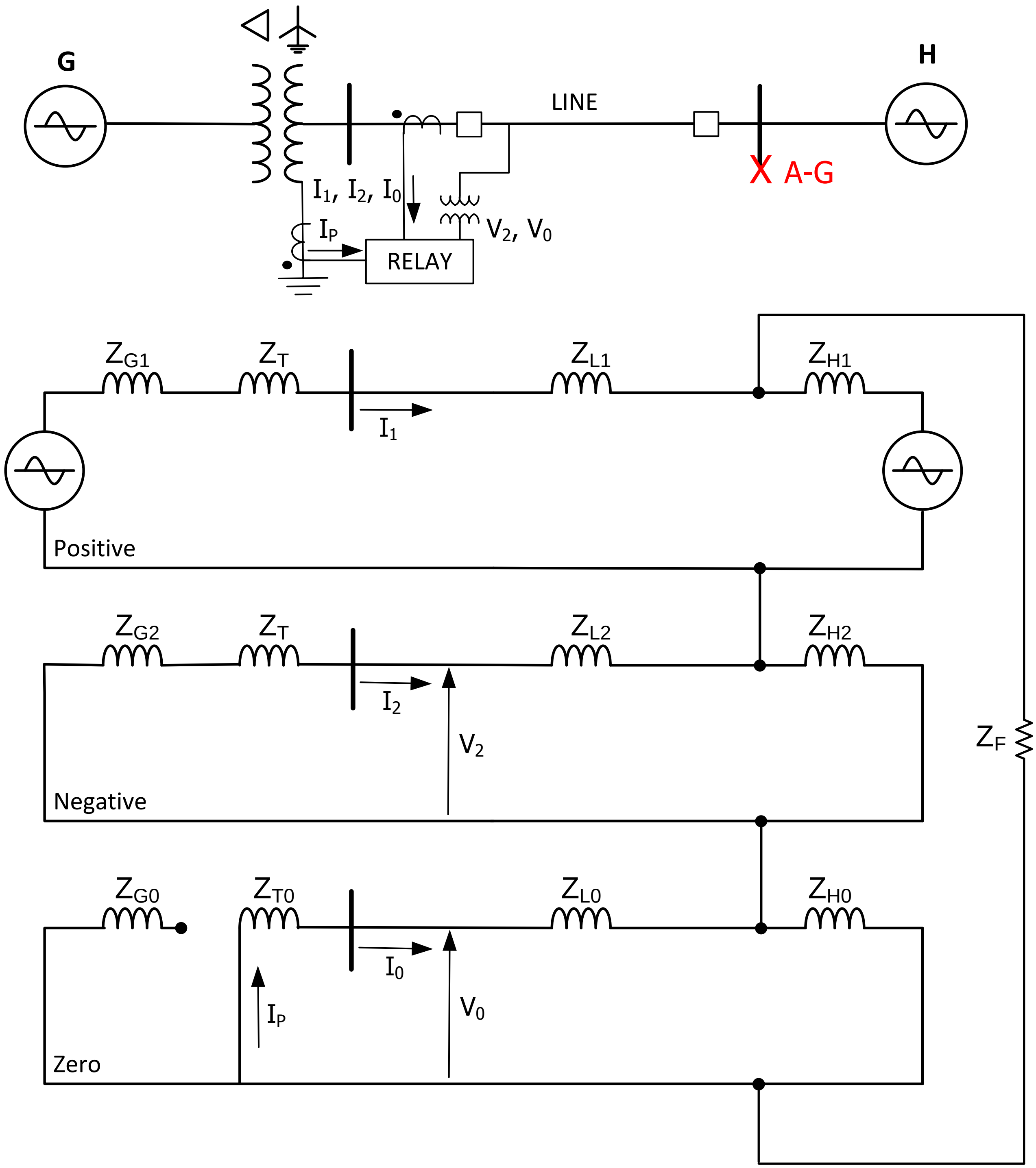

Figure 2.0.0: Sequence Network for Various Polarizing Sources

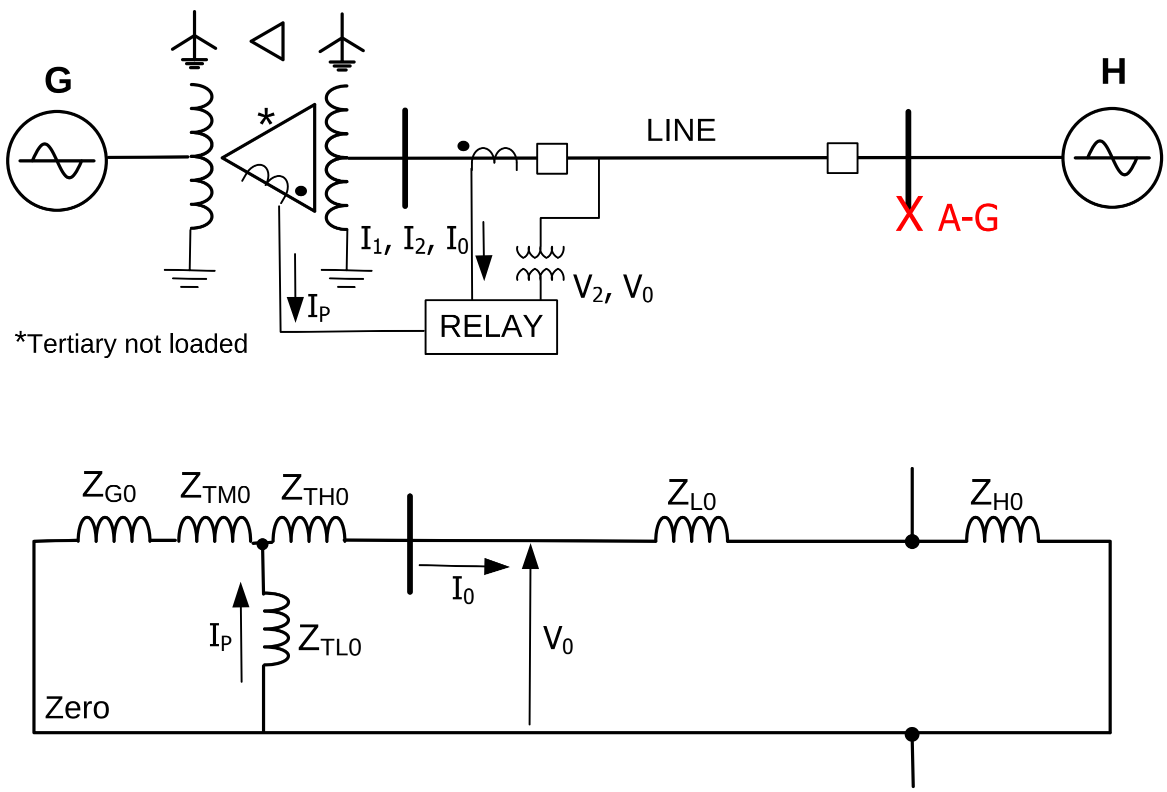

Figure 2.0.1: Sequence Network for Delta Tertiary Polarizing Source

3.0 Identify Different Methods of Polarizing for Ground Directional Elements

3.1 Zero Sequence Voltage

The residual fault current measured by the zero sequence overcurrent element may be the result of a fault on any one of the three phases. In order for the associated directional element to respond correctly a voltage must be derived related to the same phase that has been faulted. The system residual voltage which is the vector sum of the individual phase voltages will provide the correct reference quantity. The derived quantity is 3V0 using symmetrical component terms.

The voltage source must come from a set of three phase voltage transformers (VTs) or coupling capacitor voltage transformers (CCVTs) connected grounded wye on the primary side. The secondary connection will vary depending of the specific design. Following are the most common options:

Polarizing Voltage Derived within the Relay: The secondary of the VT or CCVT must be connected grounded wye to enable the connected relays to calculate the correct polarizing quantity. All three secondary phase to ground voltages will be connected to the relay(s).

Polarizing Voltage Derived Externally to the Relay: Here there are two options to consider.

Auxiliary Voltage Transformer Option: If this option is selected, the secondary of the VT or CCVT must be connected grounded wye. A set of three auxiliary voltage transformers connected wye on the primary and broken delta on the secondary will be connected to the secondary VT or CCVT winding. During a system unbalance any zero sequence voltage that is generated will appear across the ends of the broken delta. This is the point where the relay residual voltage polarizing input is connected. Figure 3.1.0 provides a detail of the necessary connections. It is an option to connect a set of auxiliary voltage transformers with a ratio of 1/√3 to increase the zero sequence voltage quantity. Relay input voltage ratings and the ratio of the VT or CCVT should be confirmed before using this option[1].

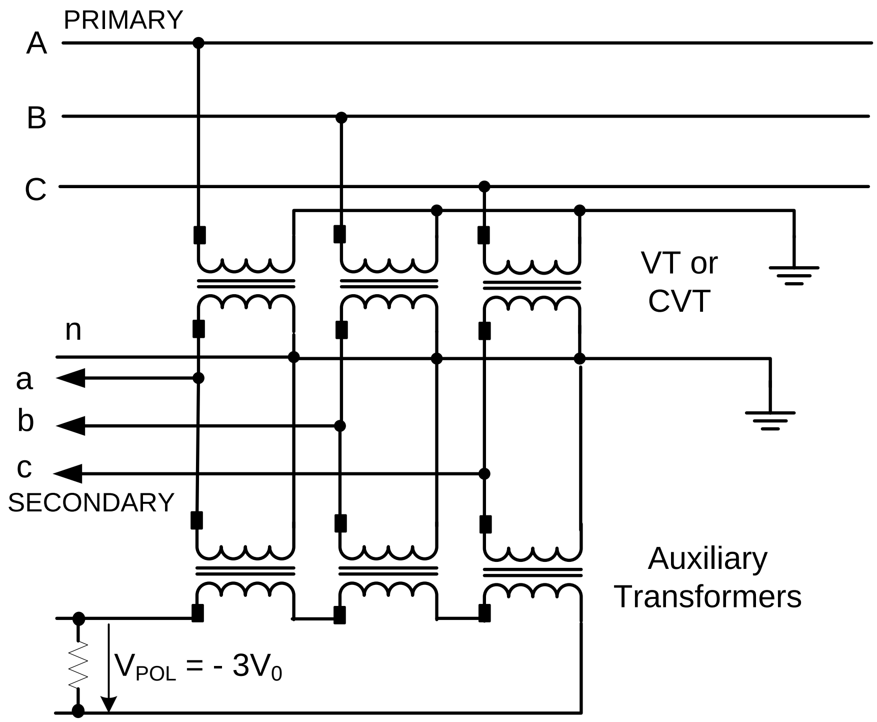

Figure 3.1.0: Accessing zero sequence polarizing voltage with a single vt secondary winding and auxiliary transformers

VT or CCVT Secondary Winding Broken Delta Option: If the VT or CCVT has a spare secondary winding that can be used exclusively for voltage polarizing it can be connected in broken delta in a manner similar to the auxiliary voltage transformers described in the paragraph above. Relay residual voltage polarizing elements would be connected directly to this winding. Check the turns ratio of the VT or CCVT to confirm that the maximum zero sequence voltage quantity will not exceed relay input voltage ratings. This connection is shown in Figure 3.1.1.

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[1]Of particular concern is the occurrence of ferroresonance due to the saturation of auxiliary voltage transformers when used with CCVTs which can result in undesirable overvoltages. "CCVT Failure due to Improper Design of Auxiliary Voltage Transformers", Davarpanah M, et all, IEEE Transactions on Power Delivery, Jan. 2012, pp. 391-400 [16] [1]

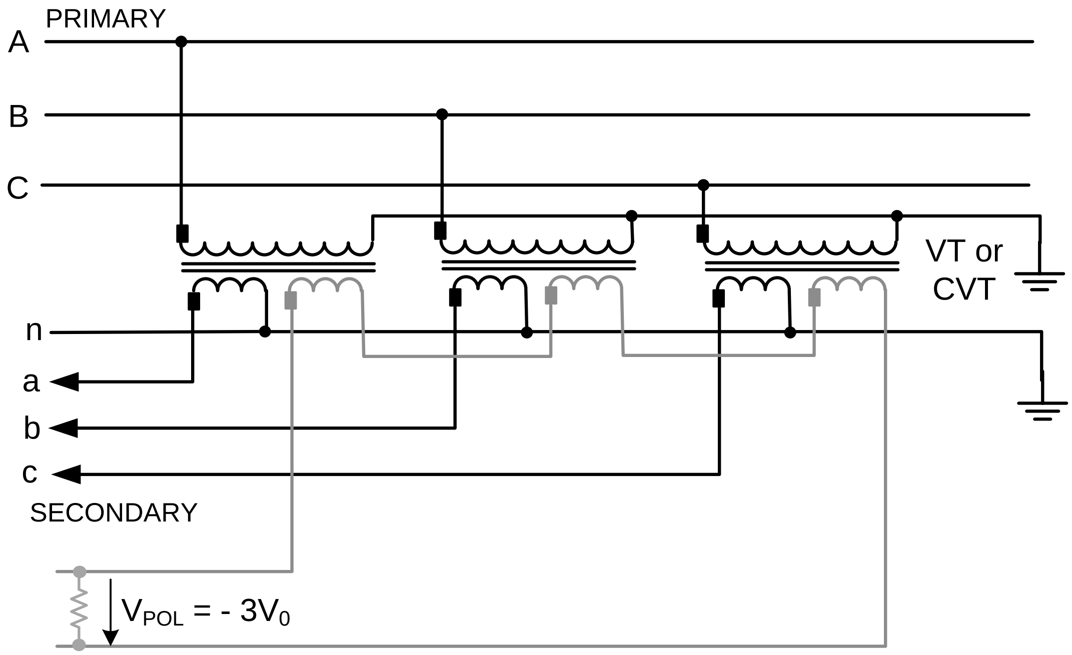


Figure 3.1.1: Accessing zero sequence polarizing voltage with a double vt secondary winding

3.2 Negative Sequence Voltage

In this method the polarizing (reference) quantity used is the negative sequence voltage (V2). The operate quantity is typically either measured or calculated residual ground current (3I0) or negative sequence current (I2).

Almost all negative sequence voltage polarized relays compare the negative sequence voltage (V2) and the negative sequence current (I2) to establish direction. The operate quantity is typically residual ground current (3I0), measured or calculated, or negative sequence current (I2). During a single line to ground fault in the forward direction, the system voltages and currents are similar to that shown in Figure 3.2.0.

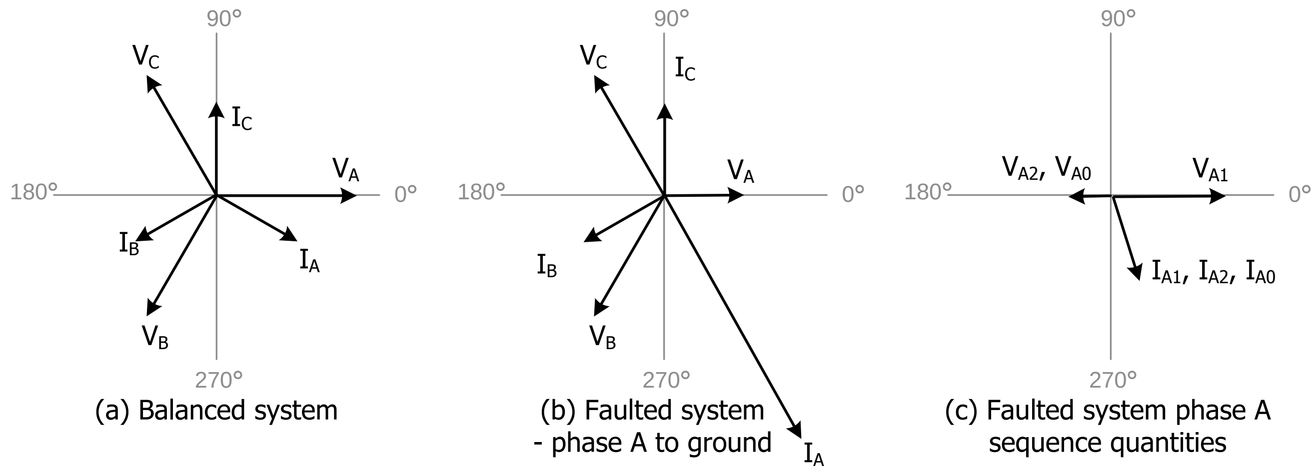


Figure 3.2.0: System Vectors, Balanced and During a Single Line to Ground (SLG) Fault

Most relays have a settable characteristic angle to take into account the transmission line angle. Usually, the forward operate region is +/- 90 degrees from the characteristic angle. Variations of this basic directional technique include having a separate forward and reverse operation region for enhanced security. Operating characteristics utilizing this principle will not necessarily be +/- 90 degrees from the characteristic angle, typically this characteristic is reduced in the reverse direction for greater trip security. Various negative sequence directional operating characteristics are shown in Figure 3.2.1 and 3.2.2. Note that RCA (Relay Characteristic Angle) is similar to MTA (Maximum Torque Angle).

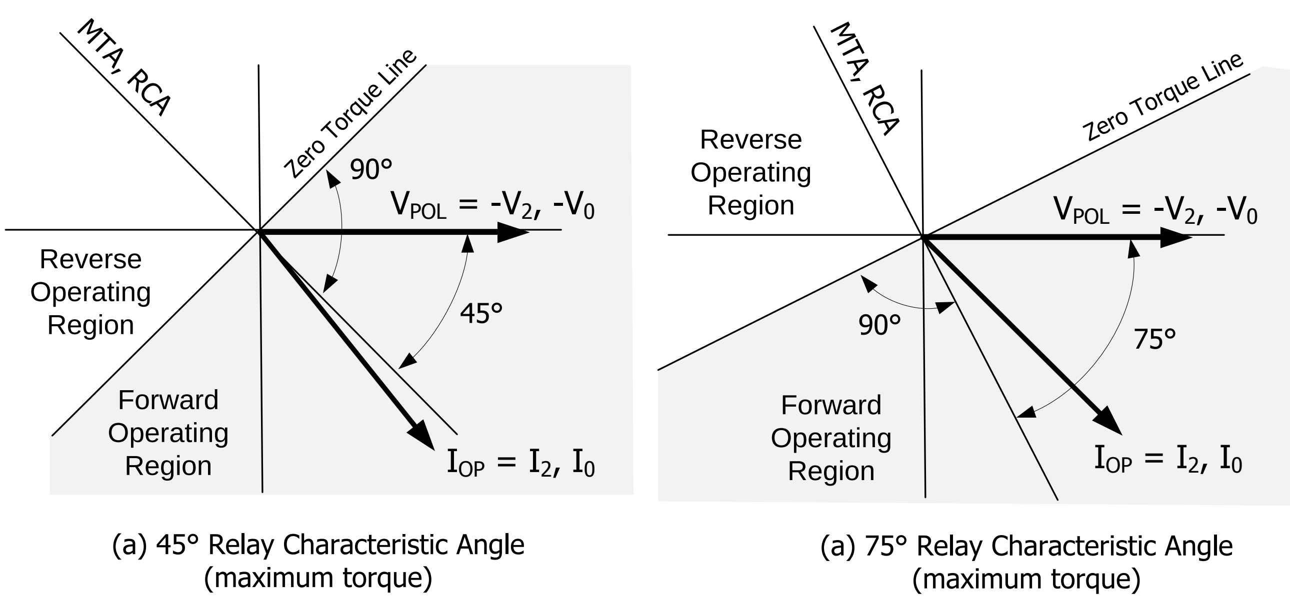


Figure 3.2.1: Directional Operating Characteristic at 45 and 75 degrees

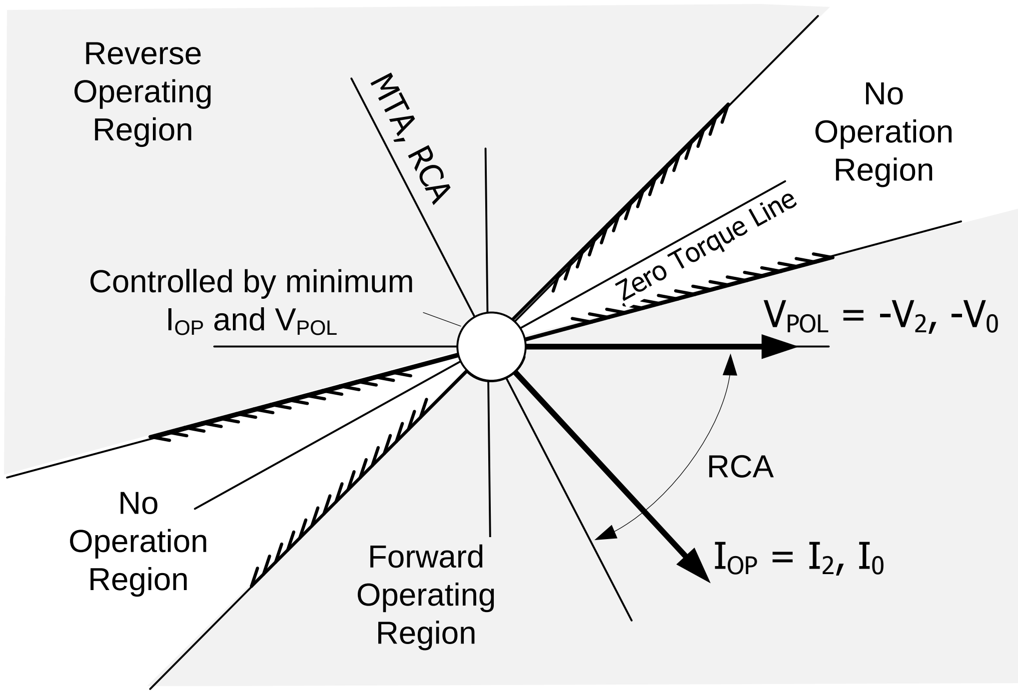


Figure 3.2.2: Forward and Reverse Directional Operating Characteristic for Greater Security

Most relays also require a minimum amount of negative sequence voltage to be present for a directional decision to be made. Most microprocessor relays give the user the option to block operation on insufficient polarizing voltage or allow the unit to become non-directional.

3.3 Zero Sequence Current (Current Polarizing)

In an unbalanced system, ground current flows in the grounded neutral of transformers. Thus, the current flow can be used for the determination of fault direction during ground faults.

A typical system is shown in Figure 3.3.0. A phase a-to-ground fault is applied with Ib and Ic at zero for simplicity. The current flowing into the fault (Ia) is essentially in phase with the current flowing in the transformer neutral (In), thus producing maximum operating torque in the ground relay. Operation occurs if the magnitudes are above the required directional unit pickup values.

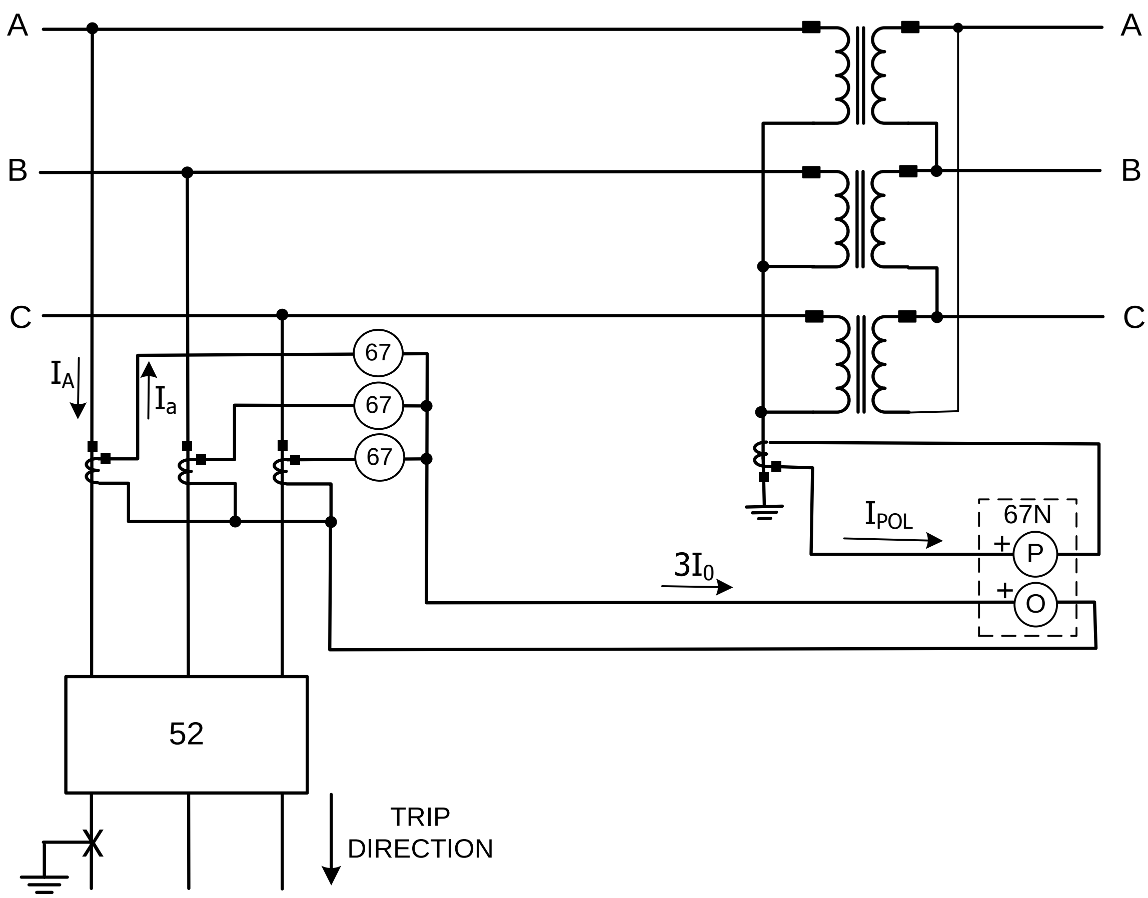
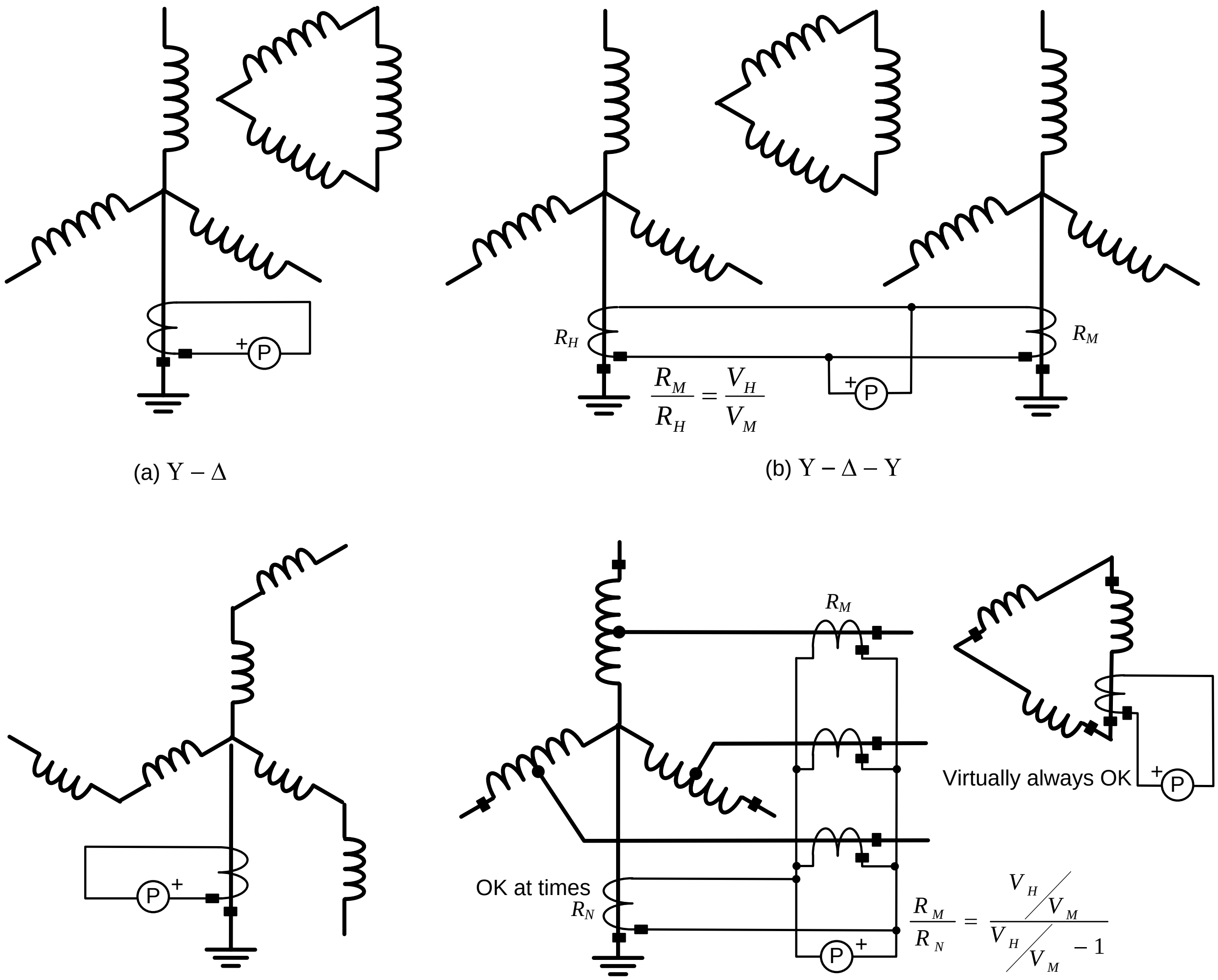


Figure 3.3.0: Current Polarizing Circuit

Several methods of obtaining suitable current polarizing sources exist and are shown in the next Figure 3.3.1.



(a) Y – Δ

(b) Y – Δ – Y

(c) Zig-zag

(d) Auto – with Δ tertiary

Figure 3.3.1: Current Polarizing Circuits

It is important to note that some of the methods can be incorrectly implemented and result in either reversed directionality or insufficient current quantities. The most obvious error would be connecting one of the relay directional units backwards. However, other more subtle errors exist. For example, the use of the delta tertiary winding in an autotransformer is suitable, but the quantity can be Io or 3Io, depending on number of CTs used. If the tertiary is used for load, then the CTs in each phase must be paralleled to cancel out the load current. Also, a single neutral CT of an autotransformer may not be dependable due to transformation ratio and strength of other Io sources, and in some cases the neutral current could be zero or reversed.

Also important is the performance of the CTs. In Figure 3.3.1 (b), it is best for the parallel CTs to have similar characteristics. In Figure 3.3.1 (d), the transformer neutral CT characteristics should match that of the phase CTs. All CTs should have adequate accuracy rating where the effect of CT saturation is minimized.

Another incorrect method of implementation is to use only the neutral current from a particular winding of a three-winding transformer to polarize directional elements for lines connected to that winding. For example, consider the three-winding transformer in Figure 3.3.2:

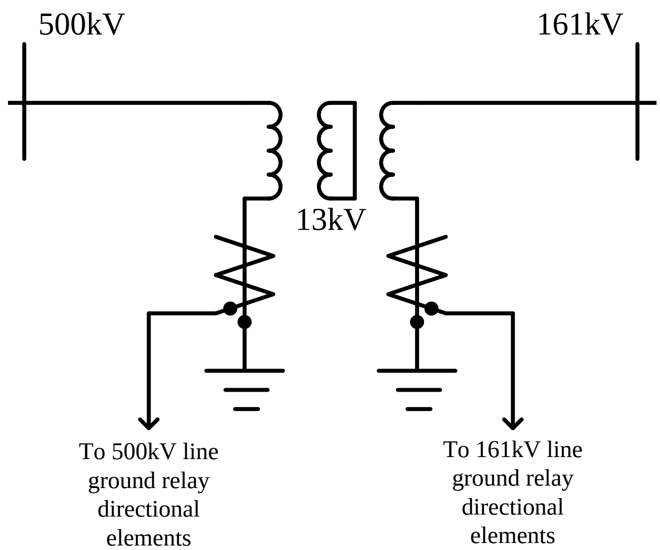


Figure 3.3.2: Incorrect Implementation of current polarizing from a three-winding transformer

As noted previously, current to polarize the directional elements should always be in the same direction. What changes is the direction of the operate current for faults on either side of a line ground relay. The decision to trip/restrain is based on the results of the comparison between fixed polarizing current reference and the direction of the line residual operate current.

However, if designed and installed as shown in Figure 3.3.2, this will not be the case. The polarizing current will reverse direction depending on whether the fault is on the 500kV or the 161kV system. This could result in incorrect directional decisions and contribute to relay misoperations.

Consider a phase-to-ground fault on the 500kV bus, as shown in Figure 3.3.3. 500kV line relays will see polarizing current up the neutral, which will enter the polarity mark on the directional ground relay, resulting in a correct directional decision. However, 161kV line relays will see polarizing current down the neutral, which will enter the non-polarity mark of the directional ground relay. This, compared with incoming current from 161kV lines, will result in an incorrect forward directional decision.

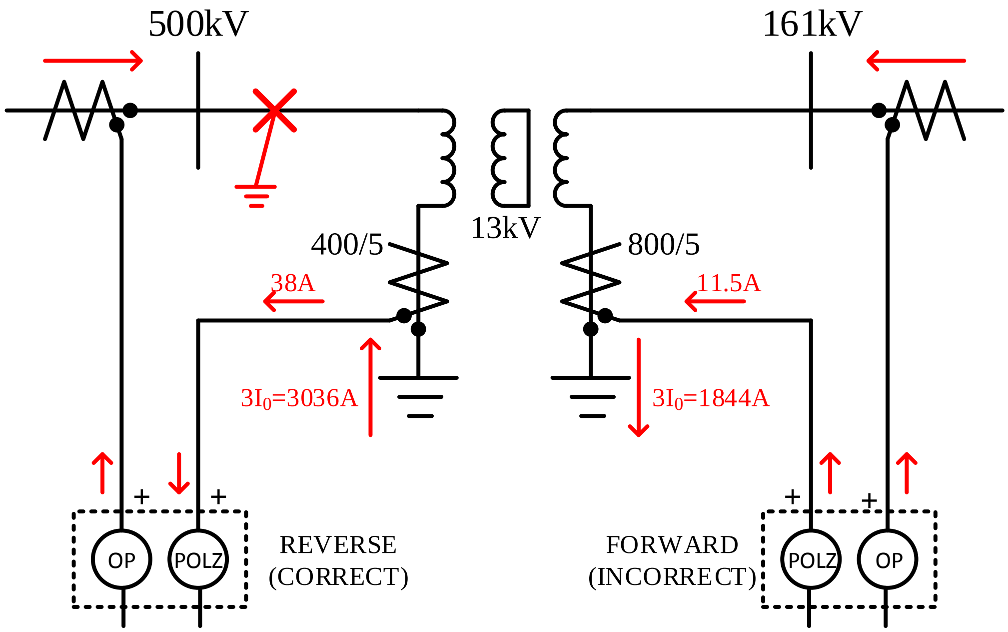


Figure 3.3.3: Ground fault on 500kV bus (Incorrect current polarization)

Now consider a phase-to-ground fault on the 161kV bus, as shown in Figure 3.3.4. 161kV line relays will see polarizing current up the neutral, which will enter the polarity mark on the directional ground relay, resulting in a correct directional decision. However, 500kV line relays will see polarizing current down the neutral, which will enter the non-polarity mark of the directional ground relay. This, compared with incoming current from 500kV lines, will result in an incorrect forward directional decision.

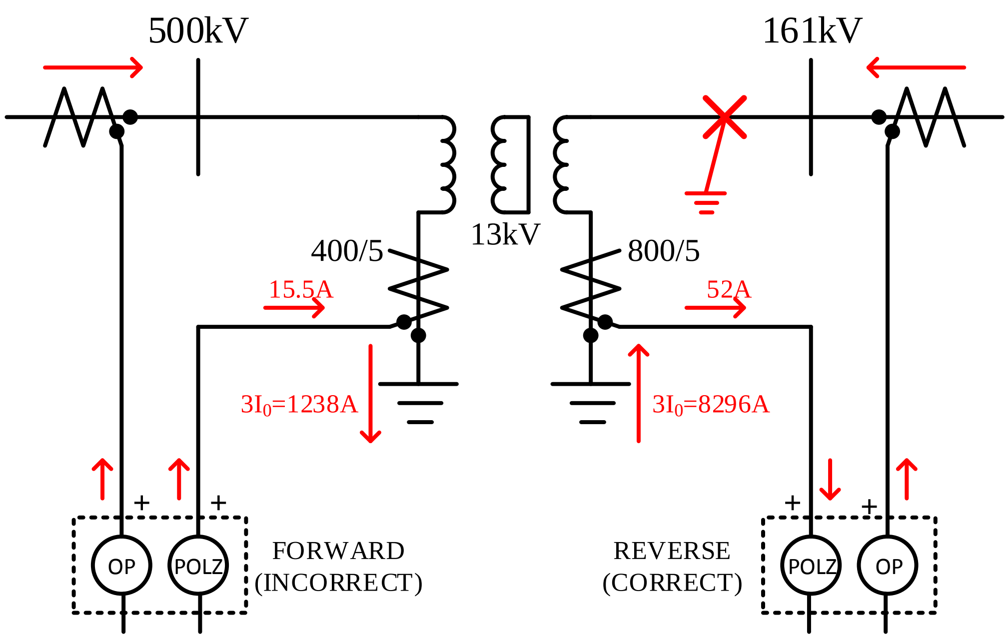


Figure 3.3.4: Ground fault on 161kV bus (Incorrect current polarization)

This is why the neutral CT ratios must be properly chosen and the two neutral currents summed, to ensure a reliable polarizing reference (see Figures 3.3.5 and 3.3.6). Regardless of the fault location, the polarizing reference is in the same direction.

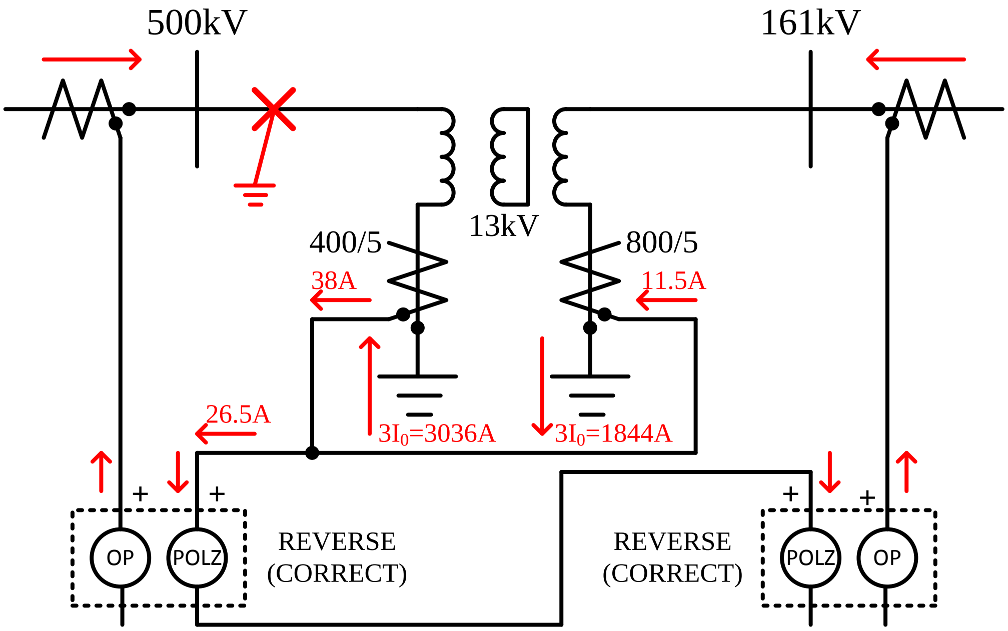


Figure 3.3.5: Ground fault on 500kV bus (Correct current polarization)

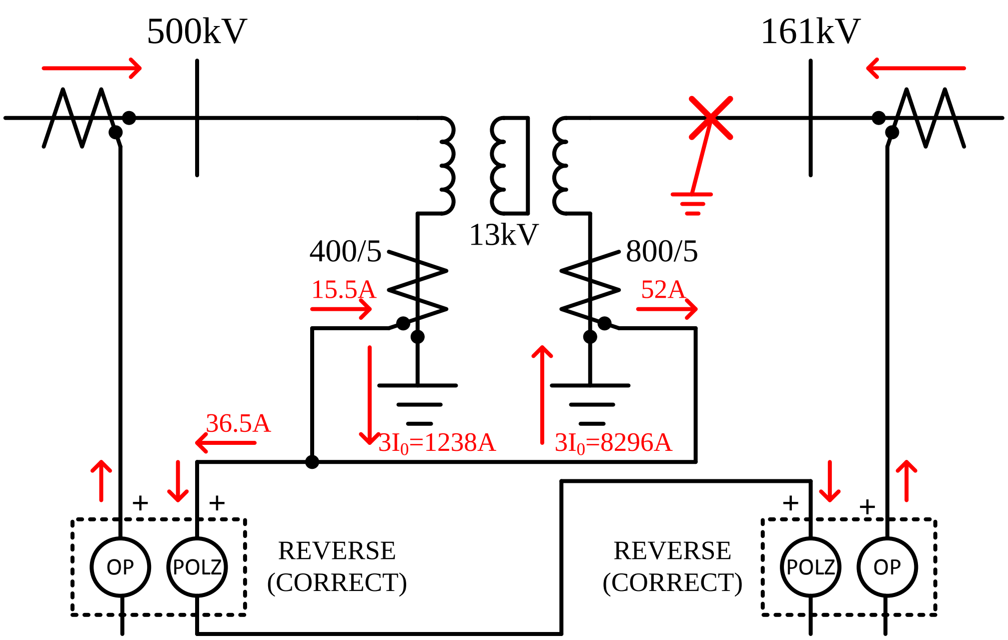


Figure 3.3.6: Ground fault on 161kV bus (Correct current polarization)

3.3.1 Using the tertiary of an autotransformer for polarizing current

It is common to provide polarizing current from the tertiary of grounded autotransformers. However, current reversal in the tertiary can be experienced if one of the equivalent branches in the transformer T model is negative and large enough to make the combined branch and source impedance from that side negative. The following example illustrates this point.

Consider a typical autotransformer and system as shown in Figure 3.3.1.0

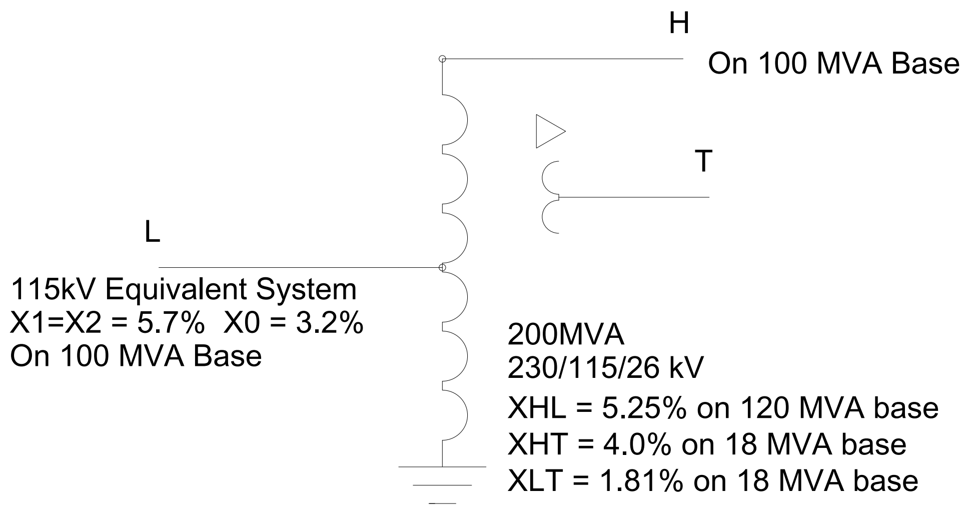


Figure 3.3.1.0: Example of Autobank Tertiary Polarizing

Converting all impedances to a common 100 MVA base gives:

XHL = 5.25*100/120 = 4.38%, XHT = 4.0*100/18 = 22.22%, XLT = 1.81*100/18 = 10.06%

Developing the T model for the transformer gives:

ZH = 0.5*(XHL + XHT - XLT) = 0.5*(0.0438 + 0.2222 - 0.1006) = 0.0827 pu
ZL = 0.5*(XHL - XHT + XLT) = 0.5*(0.0438 - 0.2222 + 0.1006) = – 0.0389 pu (negative)
ZT = 0.5*(-XHL + XHT + XLT) = 0.5*(-0.0438 + 0.2222 + 0.1006) = 0.1395 pu

Now consider the zero sequence network connections for this transformer. These can be seen in Figure 3.3.1.1.

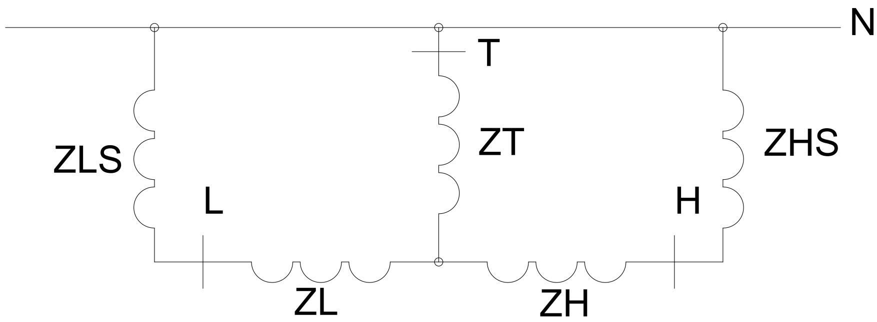


Figure 3.3.1.1: Zero Sequence Network Connections

Now assume that a low side SLG bus fault produces a current I0 of 1.0 pu as is shown in Figure 3.3.1.2 (positive and negative sequence network omitted for clarity).

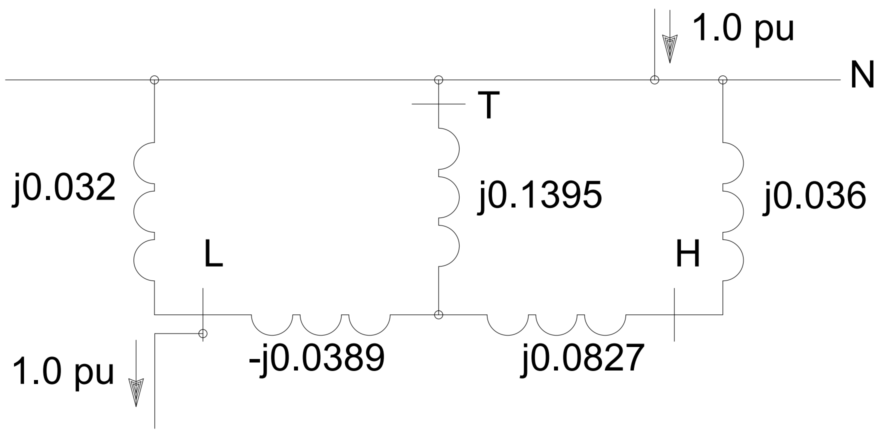


Figure 3.3.1.2: Lowside SLG bus fault

Reducing the network, starting from the right side gives:

→ ((0.036 + 0.0827)*0.1395)/(0.036 + 0.0827 + 0.1395) = j0.064 pu
X0 = ((0.064 - 0.0389)*0.032)/(0.064 - 0.0389 + 0.032) = j0.0141 pu

Now current distribution factors for each branch in the network can be calculated:

Into the ZLS path we have:

(0.064 - 0.0389)/(0.064 - 0.0389 + 0.032) = 0.440 pu

Into the ZHS path we have:

(1 - 0.440)*0.1395/(0.1395 + 0.036 + 0.0827) = 0.303 pu

Across the ZT path we have:

(1 – 0.440)*(0.036 + 0.0827)/(0.1395 + 0.036 + 0.0827) = 0.257 pu

Figure 3.3.1.3 shows the current distribution through the transformer for the low side SLG bus fault. Note that the I0 current that will circulate inside the delta for this fault flows from polarity towards non-polarity on the windings that comprise the delta. This I0 in the tertiary branch (0.26 p.u.) is 180° out of phase with the I0 flow of non-polarity towards polarity across the M branch (0.56 p.u.).

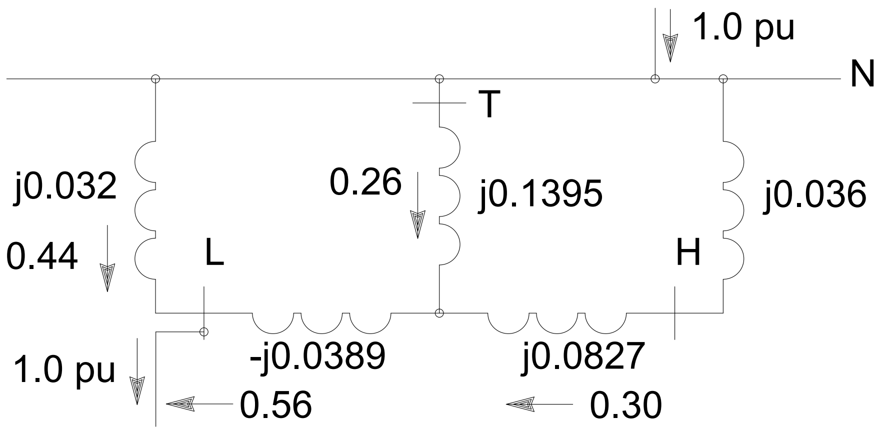


Figure 3.3.1.3: Zero Sequence current distribution through the autotransformer for a lowside SLG bus fault

Now assume that a high side SLG bus fault produces a current I0 of 1.0 pu as is shown in Figure 3.3.1.4.

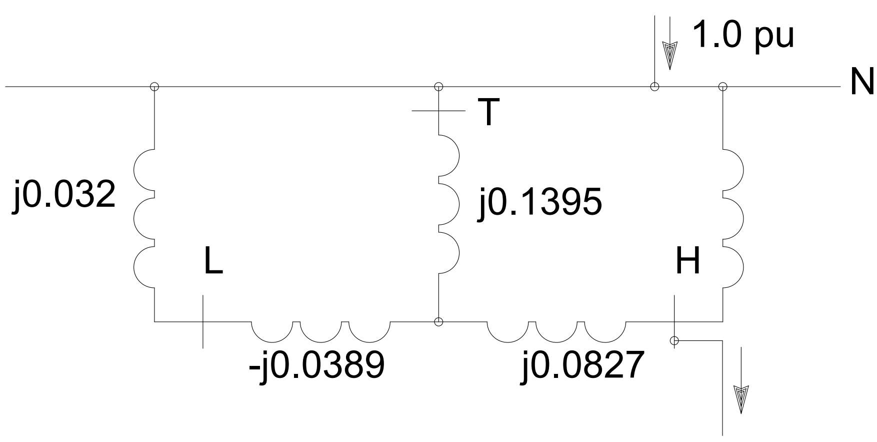


Figure 3.3.1.4: Highside SLG fault

Reducing the network, starting from the left side gives:

→ (0.032 – 0.0389)*0.1395/(0.032 - 0.0389 + 0.1395) = – j0.0073 pu
X0 = (-0.0073 + 0.0827)*0.036/(-0.0073 + 0.0827 + 0.036) = j0.0244 pu

Now current distribution factors for each branch in the network can be calculated:

Into the ZHS path we have:

$$(-0.0073 + 0.0827)/(-0.0073 + 0.0827 + 0.036) = 0.677 \text{ pu}$$

Into the ZLS path we have:

$$(1-0.677)*0.1395/(0.1395 + 0.032 - 0.0389) = 0.340 \text{ pu}$$

Across the ZT path we have:

$$(1-0.677)*(0.032 - 0.0389)/(0.1395 + 0.032 - 0.0389) = -0.0168 \text{ pu}$$

Figure 3.3.1.5 shows the current distribution through the transformer for the high side SLG bus fault. Note that the I0 current that will circulate in the tertiary flows from non-polarity towards polarity across the windings that make up the delta. This I0 in the tertiary branch (0.02 p.u.) is in phase with the I0 flow of non-polarity towards polarity across the H branch (0.32 p.u.). This makes the tertiary an unsuitable polarizing source.

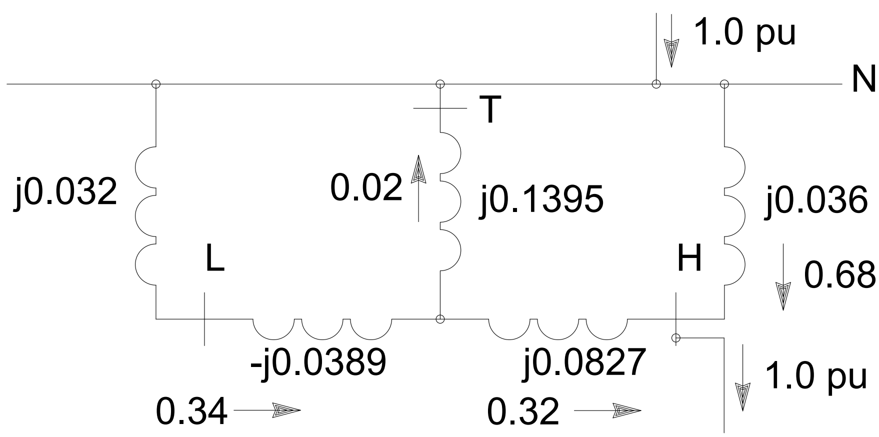


Figure 3.3.1.5: Zero Sequence current distribution through the autotransformer for a highside SLG bus fault

As can be seen from the above calculations, this example shows that the tertiary of an autobank may prove unreliable for polarizing currents for some combinations of transformer and system impedances. This will occur anytime a transformer T-model branch impedance is negative and sufficiently large to make the combined bank and source impedance negative.

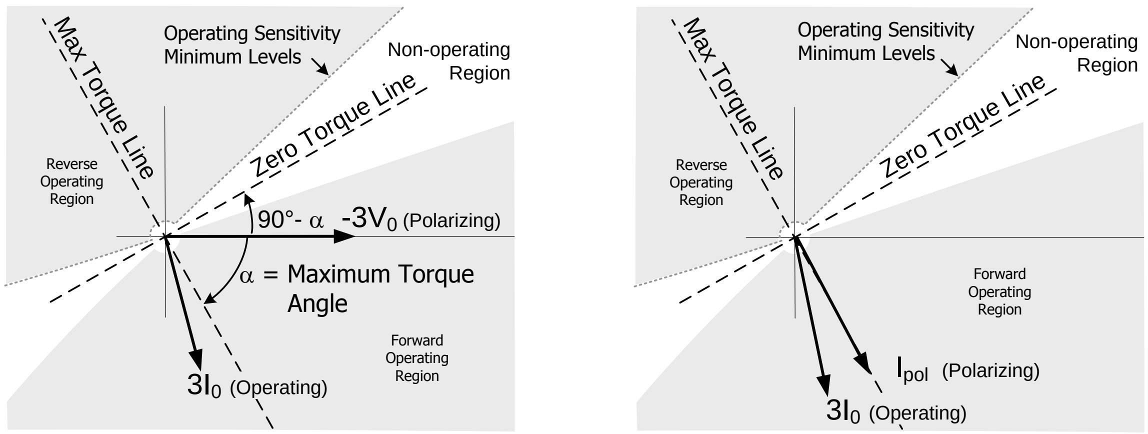
3.3.2 Specifying Polarizing CT Ratio

Current transformer ratios are selected to provide adequate current to operate the connected relays under minimum conditions, supply the complete circuit burden, and not allow excessive currents for a maximum fault. Where two or more current polarizing sources are used, the CT ratios should be selected to provide approximately equal secondary currents from each source (not all identical CT ratios) so that when one transformer is out of service the remaining polarizing current is adequate. Typical steps for specifying CT used for polarizing are:

I. Find fault currents:
   a. Minimum Remote end fault current I (min) under different contingencies at local substation.
   b. Maximum fault current I(max) under different contingencies at local substation
II. CT ratio selection:
   a. Single CT source such as delta-wye transformer, autotransformer (neutral or tertiary winding)
      i. Select CT ratio such that minimum CT secondary current is equal or greater than the relay minimum pickup (typically 0.5 amps), and also make sure that CT does not saturate for I (max) fault current.
   b. Two CTs such as wye-wye-delta transformer
      i. The LV and HV CT neutral ratio should be inversely proportional to transformer winding ratio
      ii. Select the HV CT neutral (CTHvn) or LV CT neutral (CTLvn) ratio such that minimum CT secondary current is equal or greater than the relay minimum pickup (typically 0.5 amps), and also make sure that CT does not saturate for I (max) fault current

3.4 Dual Polarizing, combination of zero sequence voltage and zero sequence current

Dual polarizing describes the application where the residual ground current 3I0 measured at the relay is polarized by zero sequence voltage, −3V0, measured at the relay and a zero sequence current, IPol, measured at a grounding transformer. This application is desirable because polarizing current, IPol, from the transformer, if measured correctly (refer to Section 3.3), generally provides much more sensitivity to remote faults than does polarizing voltage, −3V0. Polarizing voltage is adaptively used in the event when the transformer providing the polarizing current is removed from service, i.e. IPol = 0.



Zero Sequence Voltage Polarized
Directional Ground Fault Function

Transformer Zero Sequence Current Polarized
Directional Ground Fault Function

Figure 3.4.0: Dual Polarizing

Refer to Figure 3.4.0 for basic directional characteristics using zero sequence voltage and zero sequence current polarization separately. In some electromechanical designs, there may be two separate directional units (one for voltage polarizing and one for current polarizing) with their forward (closing torque) operating contacts arranged in parallel so that either unit may indicate forward ground fault direction. Other electromechanical implementations may have a single directional unit that has both zero sequence voltage and zero sequence current polarizing elements acting simultaneously on the same unit, so that a single contact that operates on the sum of the torque is developed by the two methods. In microprocessor relays there are different considerations because of their increased sensitivity provided by numerical calculations.

As previously discussed in Section 3.3, if a grounding transformer zero sequence current polarization source is available, then dual polarization with IPol and –3V0 may be desirable because of IPol's greater sensitivity to ground faults than –3V0. It is this difference in sensitivity that gives rise to an issue, which if not correctly addressed, will result in incorrect directional comparison at the line terminals and incorrect pilot tripping.

Directional units based on symmetrical component theory depend on reasonably stable balanced three phase voltages and currents, and that during the fault condition non-faulted phases are not appreciably affected. This is essential if we are to rely on zero and negative sequence voltages as polarizing voltages for ground directional units. During the analysis of directional unit operations for remote (external to the protected line) single phase-to-ground faults, unbalanced voltages in the non-faulted phases have been observed. The source of the unbalance is not certain, but is expected to be the result of non-transposed lines or other unbalanced phase and/or load impedances. In some cases for very remote faults these unbalanced voltages have caused a significant change of the zero sequence polarizing voltage angle resulting in a different directional determination than expected. This effect is discussed in Section 4.2 and illustrated in Figure 4.2.3: The Effect of Unbalanced Phase Voltages on Voltage Polarization

To overcome this issue with zero sequence voltage polarization two basic approaches have been applied. One method is the simple paralleling (OR gate) of the appropriate outputs of the two units, however, the voltage polarizing unit is blocked if polarizing current is available. The voltage unit will only operate if polarizing current is not available, which is generally determined by setting and indicates that the transformer or its polarizing source is out of service. Simplified logic is shown in Figure 3.4.1.

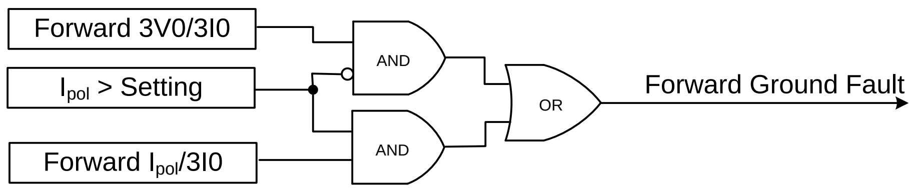


Figure 3.4.1: Dual Polarizing Logic

Figure 3.4.2 illustrates an alternate approach to dual polarization by summing the polarizing voltage phasor, –3V0, and the polarizing current phasor rotated by the angle α, the arg(V0/I0) for a strong forward fault.

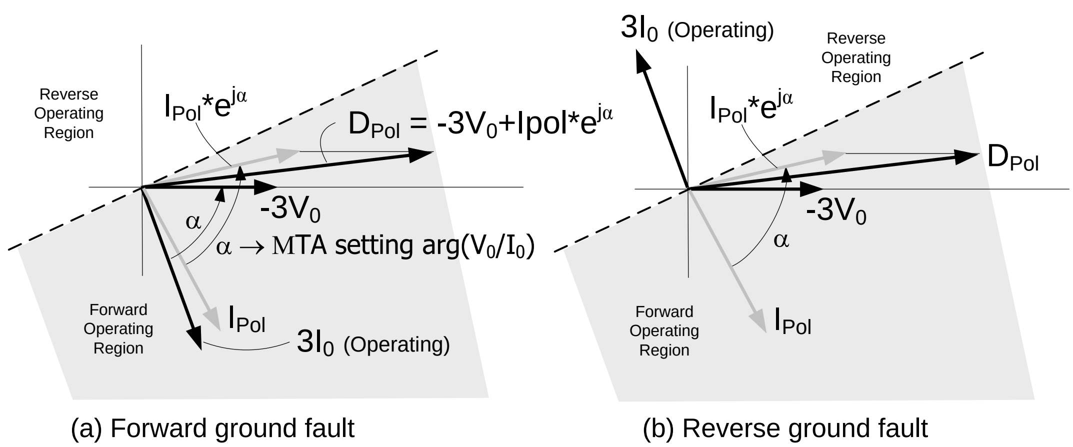
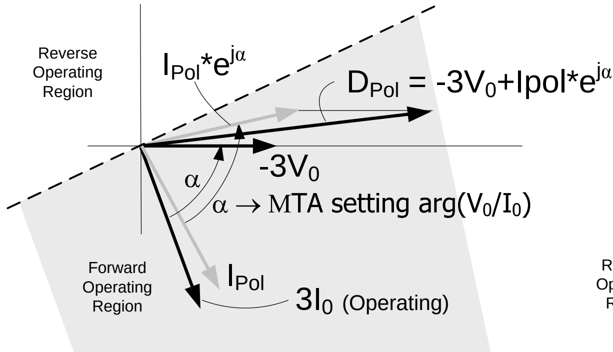
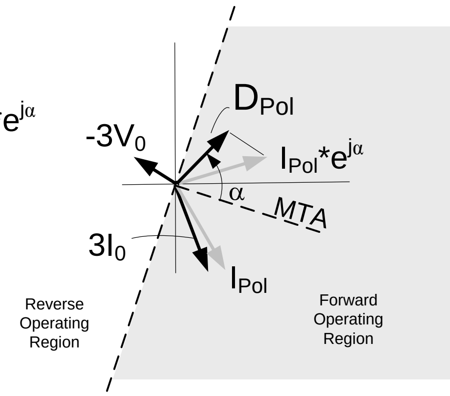


Figure 3.4.2: Dual Polarization Characteristics

This is of no consequence when using dual polarization because there is sufficient zero sequence current polarization, IPol, to overcome the –3V0 error. This is illustrated in Figure 3.4.3 where correct fault direction is determined for both a healthy and erroneous –3V0 using dual polarization.



(a) Dual polarization with healthy $3V_0$

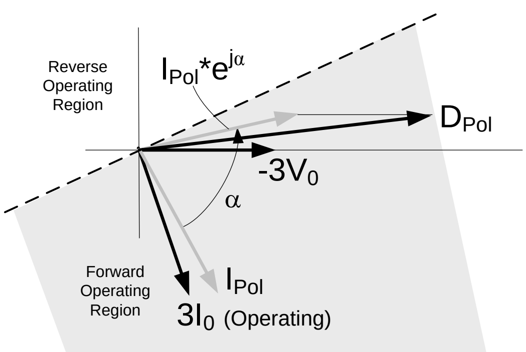


(b) Dual polarization with erroneous $3V_0$

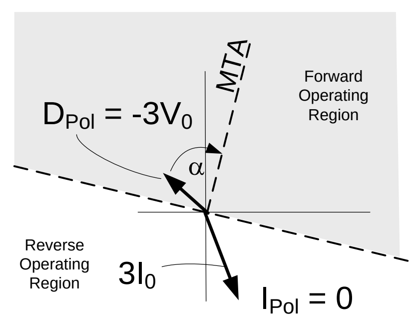
Figure 3.4.3. Dual polarization for forward fault with healthy and erroneous 3V0

The forward and reverse operating regions are referenced to the polarizing quantity DPol

A remaining issue for both methods is what happens when the transformer that is providing the IPol is removed from service. The effect of this condition with an erroneous –3V0 is shown in Figure 3.4.4. The dual polarized quantity is totally dependent on -3V0 for correct polarization and as previously discussed this quantity could be in error. This could lead to incorrect directional comparison decisions if one terminal is operating with both IPol and –3V0 while the other terminal is operating with –3V0 only.



(a) Forward ground fault with I_{Pol}



(b) Forward ground fault appearing reverse without I_{Pol} and with erroneous $3V_0$

Figure 3.4.4: Incorrect operation of a dual polarized directional unit

Keep in mind that 3V0 is usually very small where such error exists and in these cases it is recommended to set a minimum operating setting for 3V0 polarization if such a setting is available. This will not allow operation of a directional unit where the value of 3V0 measured at the relay is below the setting. If a setting is not available then it is recommended to change the settings to 3V0 at the remote terminals. The same polarizing quantities at all line terminals for pilot applications are required.

3.5 Negative and Zero Sequence Impedance

A traditional compensated negative sequence directional element has a torque equation as shown in equation 1 below.

$$T_{neg\_seq} = Re[(V_2 - \gamma \cdot Z_{Line2} \cdot I_2) \cdot (Z_{Line2} \cdot I_2)^*] \qquad \text{Eq. 1}$$

Where: V_2 = Negative sequence voltage
I_2 = Negative sequence current
Z_{Line2} = Negative sequence line impedance
γ = Compensation factor
$*$ = Conjugate

Figure 3.5.0 is sketch of the sequence network for a single line to ground fault in front of the relay measuring point.

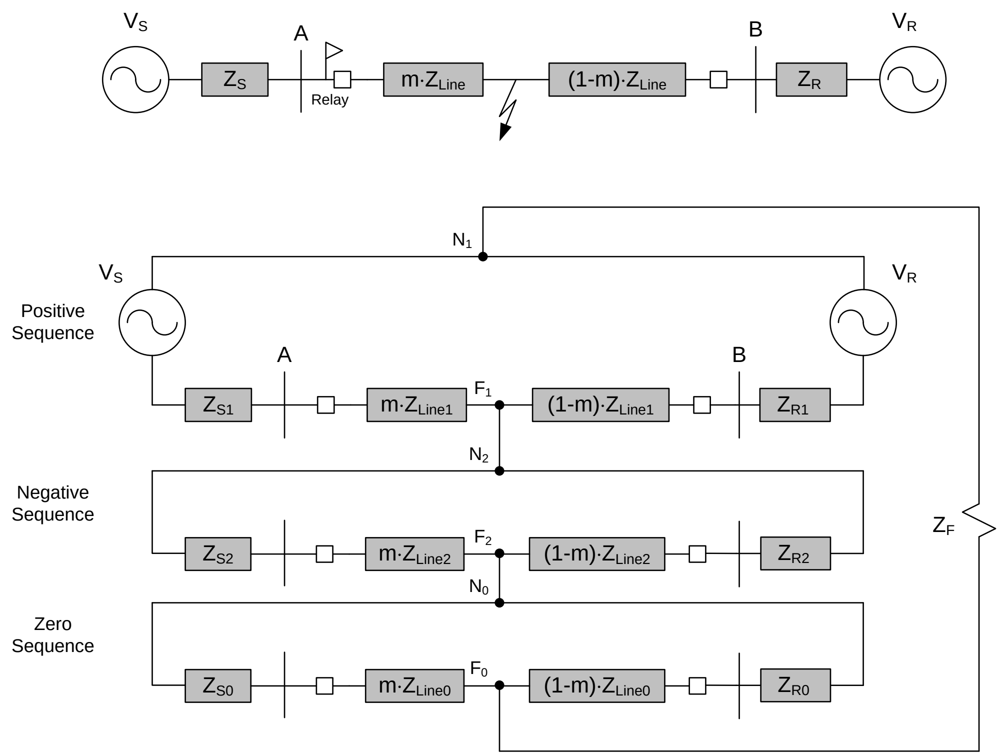


Figure 3.5.0: Sequence Network for Midline Single-line-to-ground Fault

For the negative sequence directional element we are actually only interested in the negative sequence branch and the voltage profile in this branch.

Figure 3.5.1 is a sketch of the negative sequence voltage profile for a single line to ground fault in front of the relay (forward direction)

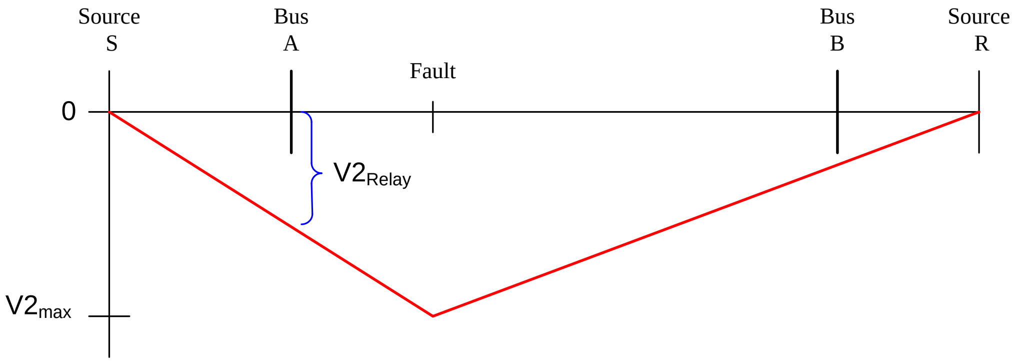


Figure 3.5.1: Negative Sequence Voltage Profile

We can see from Figure 3.5.1 that the stronger the Source S becomes ("shorter" distance between Source S and bus A), the smaller the magnitude of the negative sequence voltage, this is the reason for the compensation. For a forward fault the compensation voltage adds to the measured relay voltage (thereby boosting the negative sequence voltage), whereas for a reverse fault it subtracts from the measured voltage (thereby bucking the negative sequence voltage). The compensation factor is selected such that under no condition a reverse fault appears as a forward fault. A typical value for the compensation factor (γ) is unity.

Using a value of $\gamma = 1$, and the balance point of the compensated negative sequence torque equation [1], we can come up with a new quantity known as the negative sequence impedance to determine directionality.

From Equation [1]:

$$T_{neg\_seq} = Re[(V_2 - 1 \cdot Z_{Line_2} \cdot I_2) \cdot \left(Z_{Line_2} \cdot I_2\right)^*]$$

At the Balance point we know torque is zero ($T_{neg\_seq} = 0$)

$$Re\left[\left(V_2 - 1 \cdot Z_{Line_2} \cdot I_2\right) \cdot \left(Z_{Line_2} \cdot I_2\right)^*\right] = 0$$
$$Re\left[(V_2) \cdot \left(Z_{Line_2} \cdot I_2\right)^*\right] = Re\left[(Z_{Line_2} \cdot I_2) \cdot \left(Z_{Line_2} \cdot I_2\right)^*\right]$$

But we know that:

$$Z_{Line\ 2} = \left|Z_{mag}\right| \angle \theta_2$$
$$\left|Z_{mag}\right| \cdot Re[V_2 \cdot (\angle \theta_2 \cdot I_2)^*] = \left|Z_{mag}\right|^2 \cdot |I_2|^2$$

Dividing both side by $|Z_{mag}|$ and solving for $|Z_{mag}|$:

$$\left|Z_{mag}\right| = \frac{Re[V_2 \cdot (\angle \theta_2 \cdot I_2)^*]}{|I_2|^2}$$

Where $|Z_{mag}|$ is equal to the measured negative sequence impedance.

Note, zero sequence impedance is obtained similarly, utilizing the zero sequence components and the zero sequence line impedance.

3.6 Virtual polarization

A ground fault protection scheme requires that a local residual current is compared to a local polarizing voltage, and depending on the relative angular displacement of the two vectors, a forward or reverse decision can be made. The ground fault relay operation is only reliable if there is a sufficient polarizing quantity that is greater than that which could be generated by equipment tolerances or load unbalance. This is difficult to guarantee when ground fault protection by its nature is applied to detect high resistance faults of 50 to100's of ohms. This will often generate negligible sequence component quantities that are used by traditional relays.

The main advantage of virtual polarization as used with some relays is that the relay can trip by this method of polarizing, even if traditional polarizing quantities ("3V2" negative sequence, or "3V0" residual voltage) might be zero. Provided that a phase selector has identified the faulted phase (suppose phase A), it will remove that phase from the residual voltage, V_N, calculation $V_A + V_B + V_C$, leaving only $V_B + V_C$. The resultant polarizing voltage will have a large magnitude, and will be in the same general direction as $-V_N$. This provides a substitute pseudo "residual voltage" for polarizing. The table below shows how the phase selector and virtual polarization interact to give true directionality for all faults. The phase selector must be sufficiently sensitive to provide correct operation even in the event of high resistance faults.

This technique of subtracting the faulted phase is given the description "virtual polarizing" as it removes the need to use current polarizing from a CT in a transformer star (wye)-ground connection behind the relay. This could have been necessary with traditional relays.

Phase Selector Pickup	**Virtual Residual, V_N polarizing**
A Phase fault	$V_B + V_C$
B Phase fault	$V_A + V_C$
C Phase fault	$V_A + V_B$
No selection	$V_A + V_B + V_C$

Table 3.6.0: "Residual Voltage" used for Ground Directional Overcurrent Protection

3.7 Voltage Compensation

Voltage compensation provides operating current (3I0 or 3I2) compensation to the polarizing voltage (3V0 or 3V2) in applications where greater sensitivity (reach) of the polarizing quantity is required to detect forward faults. This is usually for remote faults at the end of long line applications or for resistive faults with low operating current and strong source with low source impedance. The following discussion focuses on zero-sequence polarizing, but can be similarly applied to negative sequence polarized directional relays.

Zero-sequence polarizing voltage (3V0) with zero-sequence current compensation (3I0) will be discussed using Figure 3.7.0. The same approach is used for negative sequence voltage compensation.

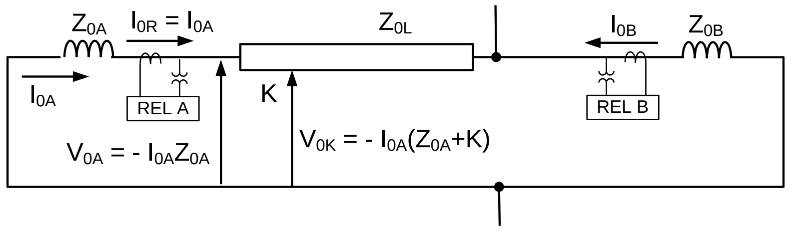


Figure 3.7.0: Zero Sequence Polarizing Network

Residual voltage V_{0A} developed at relay location for a forward line-to-ground fault with a zero sequence fault current component of I_{0A} is obtained as shown in Figure 3.7.0.

$$V_{0A} = -I_{0A} \cdot Z_{0A}$$

In the cases where the zero sequence source impedance Z_{0A} is very small the residual voltage, $3V_{0A}$, used to polarize the directional ground relay may be insufficient particularly for remote or resistive faults. Noting that Z_{0A} is predominantly inductive the polarizing voltage may be compensated (boosted) by an additional voltage of;

$$V_C = -I_{0A} \cdot K$$

where K is the compensating impedance and is usually selected as a percentage of the line zero sequence impedance. The resulting compensated polarizing voltage would be;

$$V_{0K} = -I_{0A} \cdot (Z_{0A} + K)$$

This is equivalent to moving the voltage transformers from relay terminals to a fictitious point down the line as shown in Figure 3.7.0 where there is sufficient polarizing voltage for the ground relay.

Residual voltage compensation cannot be arbitrarily applied as incorrect application may cause incorrect directional operation.

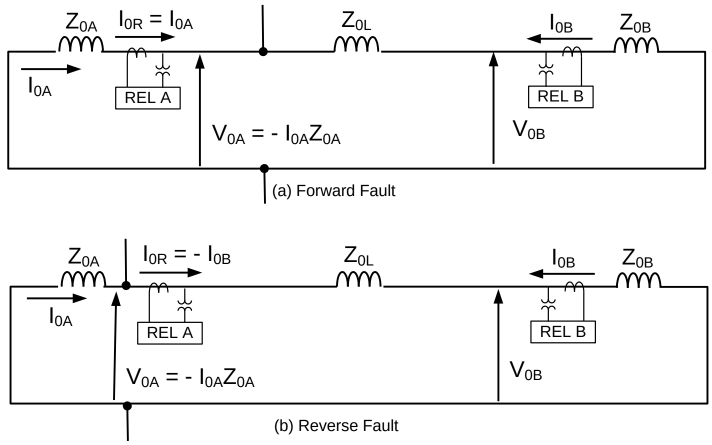


Figure 3.7.1: Zero Sequence Network for Forward and Reverse Faults

You can distinguish between two different situations, a forward fault just outside protection (REL A) at end A and a fault just behind (on the bus) protection at end A, as shown in Figure 3.7.1.

For long lines Z_{0L} can be quite high compared to source impedances. If both Z_{0A} and Z_{0B} are much less than Z_{0L} this means that for a remote end or resistive fault the fault current might not produce sufficient polarizing voltage at the relay, but the ground current is large enough to give operation. In this case it is desirable to use residual voltage current compensation to boost the polarizing voltage.

For protection REL B it doesn't matter where the fault is as long as it is forward. The operating current and polarizing voltage will be:

$$I_{0B} = -V_{0A}/(Z_{0L}+Z_{0B})$$
$$V_{0B} = V_{0A}*Z_{0B}/(Z_{0L}+Z_{0B})$$

The closer to B the fault is the higher the current I_{0B} and voltage V_{0B} will be. This doesn't matter since both $K*I_{0B}$ and $-V_{0B}$ gives the same directionality. This is provided that polarizing angle RCA (angle between polarizing voltage and ground current) is correctly set close to Z_{0B} angle.

Now look into the protection REL A. For a forward fault the zero sequence current in the relay, I_{0R}, is equal to I_{0A} and will be a maximum of V_{0A}/Z_{0A} for a fault at the terminal. As the fault moves forward on the line away from REL A the current I_{0R} and voltage V_{0A} will decrease and both $K*I_{0R}$ and $-V_{0A}$ gives the same directionality. For a reverse fault, the current in REL A, I_{0R}, will be $- I_{0B}$ and $K*I_{0R}$ will be in the opposite direction compared to $-V_{0A}$, the polarizing voltage. This will result in incorrectly determining a reverse fault as a forward fault if $K*I_{0R}$ is greater than V_{0A}. Keeping in mind that the compensating factor is to provide the compensation necessary to have sufficient polarization to detect forward faults, but not overcompensate $-V_{0A}$ for reverse faults we must determine a maximum value for K to avoid incorrect operation for reverse faults. Consider the equations for the compensated polarization quantity with the compensating factor and I_{0R}:

$$Vpol = -V_{0A} + I_{0R} * K*e^{jRCA}$$
$$I_{0R} = - I_{0B} = V_{0A}/(Z_{0L}+Z_{0B})$$

Combining the equations we get:

$$Vpol = -V_{0A}+K*[\ V_{0A}/(Z_{0L}+Z_{0B})]*e^{\,jRCA}$$
$$Vpol = -V_{0A}[1-K/(Z_{0L}+Z_{0B})]e^{\,jRCA}$$

In order to get correct directionality with the compensation factor for a reverse fault, K must be less than ($Z_{0L}+Z_{0B}$), not considering the angle error. The source impedance Z_{0B} might vary so the smallest value provides best reliability. If Z_{0L} is much greater than Z_{0B} then the relation can be simplified into $K<Z_{0L}$. Considering that the reverse looking element may need to be more sensitive than a compensated relay at the remote terminal, a common setting is $K<0.4Z_{0L}$.

4.0 Investigate Application of Different Methods

4.1 Zero sequence mutually coupled lines

Recalling Basis of Zero Sequence Voltage Polarization

In an effectively grounded power system, the zero sequence voltage magnitude is highest at the point of a single-line-to-ground fault and decreases as it is measured at points farther from the fault location. The zero sequence fault current, normally defined as flowing from low V_0 to high V_0, will, therefore, be defined as flowing in the direction of the single-line-to-ground fault. In a typical transmission system, the angles of the impedance elements, representing the lines and transformers connecting the buses of the zero sequence network do not vary a great deal, and can be collectively referred to in terms of a characteristic angle "β ". Assuming that a bolted, single-line-to-ground fault occurs somewhere on this "typical" system, and any mutual induction between network connections can be neglected (or at least minimized) the following generalities will tend to hold true:

- The single-line-to-ground, zero sequence voltage (V_0), at each of the buses in the network, will be in the same phase angle vicinity with that existing at all the other buses; hence, the zero sequence voltage can serve as a reference for establishing direction.
- The zero sequence line current flow ($3I_0$) in each impedance connection between the buses (each defined as flowing from low V_0 to high V_0) will likewise be in the same phase angle vicinity with that flowing in all the other connections.
- Provided the line CTs are oriented with the correct polarity, for the primary zero sequence current flowing into the protected line zone, toward the direction of higher V_0 (i.e., toward the fault) the phase angle of the secondary residual current of the line CTs will tend to lead the V_0 line terminal voltage by the angle (180 - β). Furthermore, if the polarity of the V_0 polarizing voltage is reversed (as is normally the case), the zero sequence primary current flowing in the direction of the line zone toward a fault, will produce residual CT current that tends to lag the -V_0 line terminal voltage by simply the angle β . (Refer to Figure 4.1.0.)

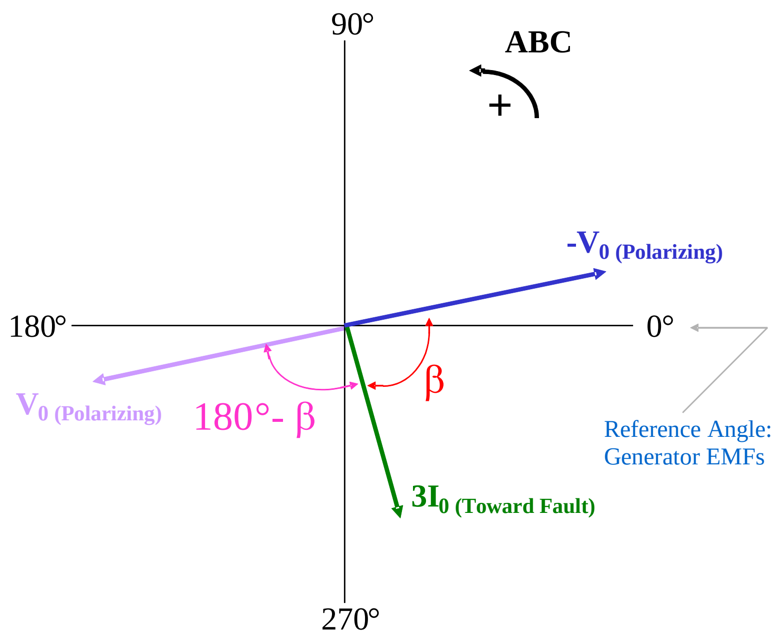


Figure 4.1.0: Zero Sequence Directional Characteristic

Recalling Basis of Zero Sequence Current Polarization

In most cases, zero sequence current sources, often available at the electrical nodes of transmission line terminals, can be used as references for directional determination. This was described in detail in Section 3.3. The section also warned that under certain circumstances, the I0 circulating in the tertiary windings of certain autotransformers may not provide a reliable phasor reference.

Regardless of where a ground fault occurs on the "typical transmission system" (described previously in the first paragraph of this Section 4.1), the phase angles of these zero sequence current source flows will change very little, while the phase angle of the residual current received from the line CT's will differ by approximately 180° for primary current flows toward faults on one side versus the other side of the CTs. Recall that the zero sequence line current flows in each impedance connection of this "typical transmission system" (when all are defined as flowing from low V_0 to high V_0) will be approximately "in-phase" with one another. The polarity of both the line and the polarizing source CTs is normally positioned so as to enable relay operation for fault current flows in the direction of the protected line section. When this is the case, the phase angle of the residual current provided by the line CTs for primary zero sequence current flows, that are toward faults in the direction of the line section, will be very close to being "in-phase" with the polarizing current by small angles that are in the vicinity of 5 to 15°.

Ramifications of Zero Sequence Mutual Coupling

As the effects of zero sequence mutual induction between the lines of a three phase, AC power system network become more significant, the generalizations supporting both voltage and current, zero sequence polarization (outlined above) become less reliable for ascertaining proper directionality. A discussion of mutual induction is necessary in understanding why this is the case.

Mutual induction refers to the voltages that appear on the conductors of one circuit line due to the currents flowing in the conductors of another. The ratio of the induced voltage in one line to the inducing current of the other is defined as the mutual impedance between the two lines. Due to the angle displacement characteristic of the positive and negative sequence phase currents, the associated magnetic fields among the three phases experience a heavy cancelling effect, causing any positive or negative sequence mutual coupling between circuits to be quite minimal (with total mutual impedance values typically well less than 10% of the total line impedance). For this reason, mutual induction is normally neglected for the positive and negative sequence components of current. The "in-phase" nature of the zero sequence component of the phase currents, conversely produces a reinforcing magnetic coupling effect, where the total mutual impedance can approach values as high as 50 to 70% of the total line impedance. If two or more transmission lines share the same right-of-way for any significant length of their total runs (whether they share the same tower structures, or not), they will likely have a significant zero sequence mutual coupling. A set of zero sequence fault currents flowing in one line will induce a set of zero sequence voltages within the other(s), and vice versa. Assuming the mutually coupled lines are within the same electrical network, the mutually induced zero sequence voltage, in any line, introduces a modification to the "network" solution of the current flow. (The "network" solution refers to the voltage and current solution for the faulted system that does not account for any mutual effects between the network connections.) Refer to Figure 4.1.1; a fault current flowing in either of the two mutually coupled lines, results in the induced zero sequence voltage indicated. Note that the polarity of the mutual voltage is such that the mutual component of the zero sequence current flow in the coupled line is opposite (180° out-of-phase) that of the inducing zero sequence current in the other line.

The following definitions apply for Figures 4.1.1, 4.1.2, and 4.1.3:

I_{0L1} = Zero sequence current flowing in Line #1
I_{0L2} = Zero sequence current flowing in Line #2
Z_{0L1} = Zero sequence self impedance of Line #1
Z_{0L2} = Zero sequence self impedance of Line #2
Z_{0M} = Zero sequence mutual impedance between Lines #1 & #2

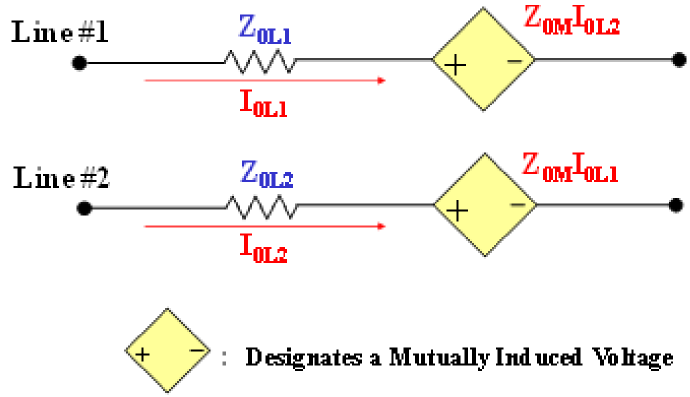


Figure 4.1.1 Simple Representation for Zero-sequence Mutually Coupled Lines

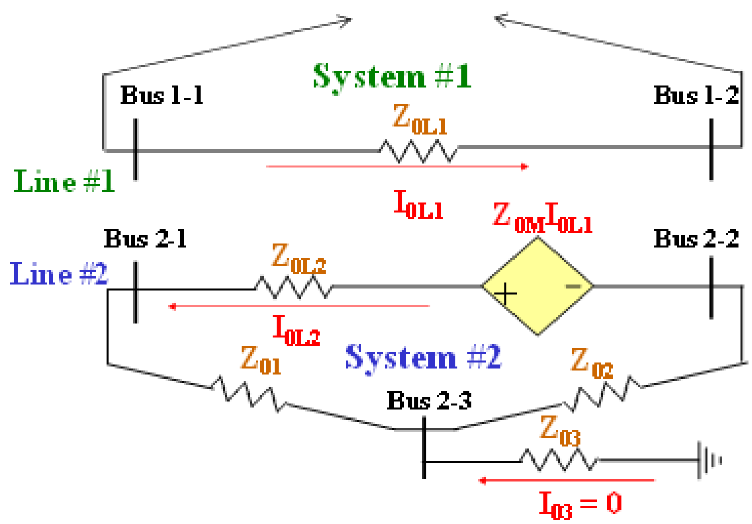


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Figure 4.1.2 Simple Single-line Diagram for Electrically Isolated Zero-sequence Mutually Coupled Lines

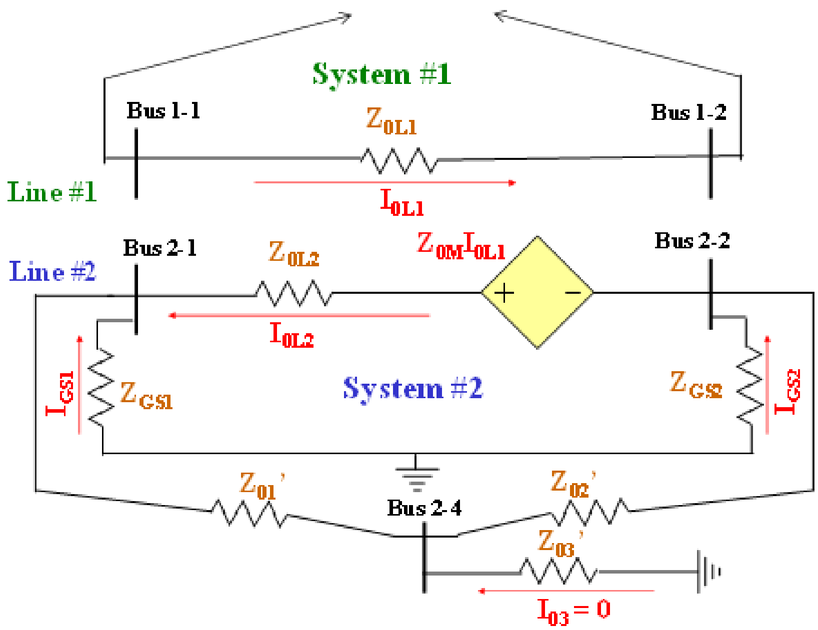


Figure 4.1.3 Simple Single-line Diagram for Electrically Isolated Zero-sequence Mutually Coupled Lines; Zero Sequence Impedance of Ground Source at Bus 2-1 and Bus 2-2 Shown

Consider the two mutually coupled transmission lines, existing in the two, otherwise, electrically isolated systems, denoted as "System 1" and "System 2" in Figure 4.1.2. Assume that both lines are protected by voltage polarized, directional overcurrent units, and that a bolted, single-line-to-ground fault, occurring somewhere in System 1, causes a set of zero sequence fault currents (I_{0L1}) to flow in Line #1. These result in a set of zero sequence voltages ($Z_{0M}\ I_{0L1}$) induced across the conductors of Line #2, causing a set of zero sequence currents (I_{0L2}) to flow.

The following impedance definitions also apply for Figure 4.1.2:

Z_{01}, Z_{02}, Z_{03} = Zero sequence impedances of the System 2 wye equivalent network existing when only Buses 2-1 and 2-2 are defined and Line #2 is removed

Inspection of Figure 4.1.2 reveals that the fault current mutually induced in System 2 will not flow in the equivalent impedance Z_{03}, and Bus 2-3 is effectively at ground potential. Thus, the zero sequence voltages at Bus 2-1 and Bus 2-2 with respect to ground are as follows:

$V_{2\text{-}1} = I_{0L2}Z_{01}$	or	$-V_{2\text{-}1} = -I_{0L2}Z_{01}$	Eq. 4.1.1
$V_{2\text{-}2} = -I_{0L2}Z_{02}$	or	$-V_{2\text{-}2} = I_{0L2}Z_{02}$	Eq. 4.1.2

Z_{01} and Z_{02} will be predominately reactive having the same general impedance angle β (mentioned previously), with the current flow through each being opposite the other with respect to ground. Instead of yielding $-V_0$ polarizing voltages at each bus that are in the same phase angle vicinity, as characteristic of the nodes of an interconnected zero sequence network, the "pure" mutual flow results in phase angles that are in the vicinity of being 180° out-of-phase. The angle between the zero sequence voltage and the zero sequence line current, monitored at each of the two buses, will be close to the angle β:

$\angle(-V_{2\text{-}1}) - \angle(I_{0L2}) \approx \beta$ Eq. 4.1.3

$\angle(-V_{2\text{-}2}) - \angle(-I_{0L2}) \approx \beta$ Eq. 4.1.4

Examination of equations 4.1.3 and 4.1.4 reveals that the voltage polarized, directional units at <u>both</u> buses will indicate a fault within Line #2; with the Bus 2-1 unit determining a false direction, in this case. A directional comparison protection scheme applied on Line #2 will, thus, undesirably operate for a fault in the magnetically coupled System 1, provided the input quantities supplied to the directional units have sufficient magnitude.

Now consider the mutually coupled transmission lines of the, otherwise, electrically isolated Systems 1 and 2, shown in Figure 4.1.3. Assume that the lines are now protected using current polarized, directional overcurrent units, and the polarizing currents are obtained from Ground Sources #1 and #2, located at buses 2-1 and 2-2, respectively.

These additional definitions apply for Figure 4.1.3

Z_{GS1} = Zero sequence impedance of Ground Source #1
Z_{GS2} = Zero sequence impedance of Ground Source #2
Z_{01}', Z_{02}', Z_{03}' = Zero sequence impedances of the System 2 wye equivalent network existing when only Buses 2-1 and 2-2 are defined and Line #2, Ground Source #1, and Ground Source #2 are removed

Again, a bolted, single-phase-to-ground fault, occurring somewhere in System 1, causes a set of zero sequence fault currents (I_{0L1}) to flow in Line #1. A set of zero sequence voltages ($Z_{0M}I_{0L1}$) is again induced across the conductors of line #2, causing a set of zero sequence currents (I_{0L2}) to flow in Line #2. As before, no current will flow in the equivalent impedance Z_{03}', and Bus 2-4 will, effectively, be at ground potential. Using current division, the following can be derived:

$I_{GS1} = -I_{0L2}Z_{01}' / (Z_{01}' + Z_{GS1})$ Eq. 4.1.5

$I_{GS2} = I_{0L2}Z_{02}' / (Z_{02}' + Z_{GS2})$ Eq. 4.1.6

As in the previous example, Z_{01}, Z_{02}, Z_{GS1}, and Z_{GS2} will be predominately reactive having the same general impedance angle β, with the current flow through each ground source being opposite the other. Instead of yielding I_0 polarizing currents at each ground source that are in the same phase angle vicinity, as characteristic of those ground sources connected to the nodes of an interconnected zero sequence network, this “pure” mutually induced flow results in phase angles that are in the vicinity of being 180° out-of-phase. The ground source zero sequence current and the zero sequence line current, monitored at <u>each</u> of the two buses, will be close to being in-phase:

$\angle(I_{GS1}) \approx \angle(-I_{0L2})$ Eq. 4.1.7

$\angle(I_{GS2}) \approx \angle(I_{0L2})$ Eq. 4.1.8

Equations 4.1.7 and 4.1.8 reveal that the current polarized, directional units at <u>both</u> buses will indicate a fault within Line #2; with the Bus 2-1 unit determining a false direction, in this case. A directional comparison protection scheme applied on Line #2 will, thus, undesirably operate for a fault in the magnetically coupled System 1, provided the input quantities supplied to the directional units have sufficient magnitude.

Summary

The previous examples illustrate the worst case situation for mutually coupled transmission lines: When the fault current flowing through the directional comparison zone of a particular transmission line (for an external fault) is due solely to the current induced by zero sequence mutual coupling, both the voltage and current polarized directional units associated with the scheme will easily indicate a false direction - resulting in an undesirable line trip. In an actual transmission system, however, lines are rarely both completely mutually coupled and electrically isolated at the same time. Generally, the component of zero sequence current flow in a magnetically coupled line that is actually due to the mutually induced voltage has a much smaller effect on the resultant line zero sequence current than the electrical network flows. (The normal network flows, recall, harmonize with the generalities supporting zero sequence polarizing.) System configurations can exist, however, where mutual effects can detrimentally alter the network flow enough to result in a false directional determination. As a precaution, when zero sequence polarization is employed, false trip checks should be done for all lines which are mutually coupled with other lines. If setting changes that would remedy the situation cannot be applied without violating the normal protection, a different method of directional determination (such as negative sequence polarizing) should be considered.

4.2 Evaluation of polarizing method considering line and source impedance, Z0 and Z2

When using negative-sequence or zero-sequence voltage polarization we should consider the various conditions that would affect the magnitude of these voltages. The magnitude of the negative- and zero-sequence voltage is directly related to the thevenin source impedance behind the relay location. In addition, VT error and untransposed lines can result in the “false” negative- or zero-sequence voltage that must be overcome by the fault generated sequence voltage in order for the directional element to operate correctly.

In this section we evaluate the magnitude of the negative- and zero-sequence voltages to determine the best choice for directional element polarization. The determination of the best sequence voltage is done by the thevenin source behind the relay with respect to the line impedance. Certain conditions may cause the sequence voltage magnitude to be so low as to not provide reliable polarizing reference.

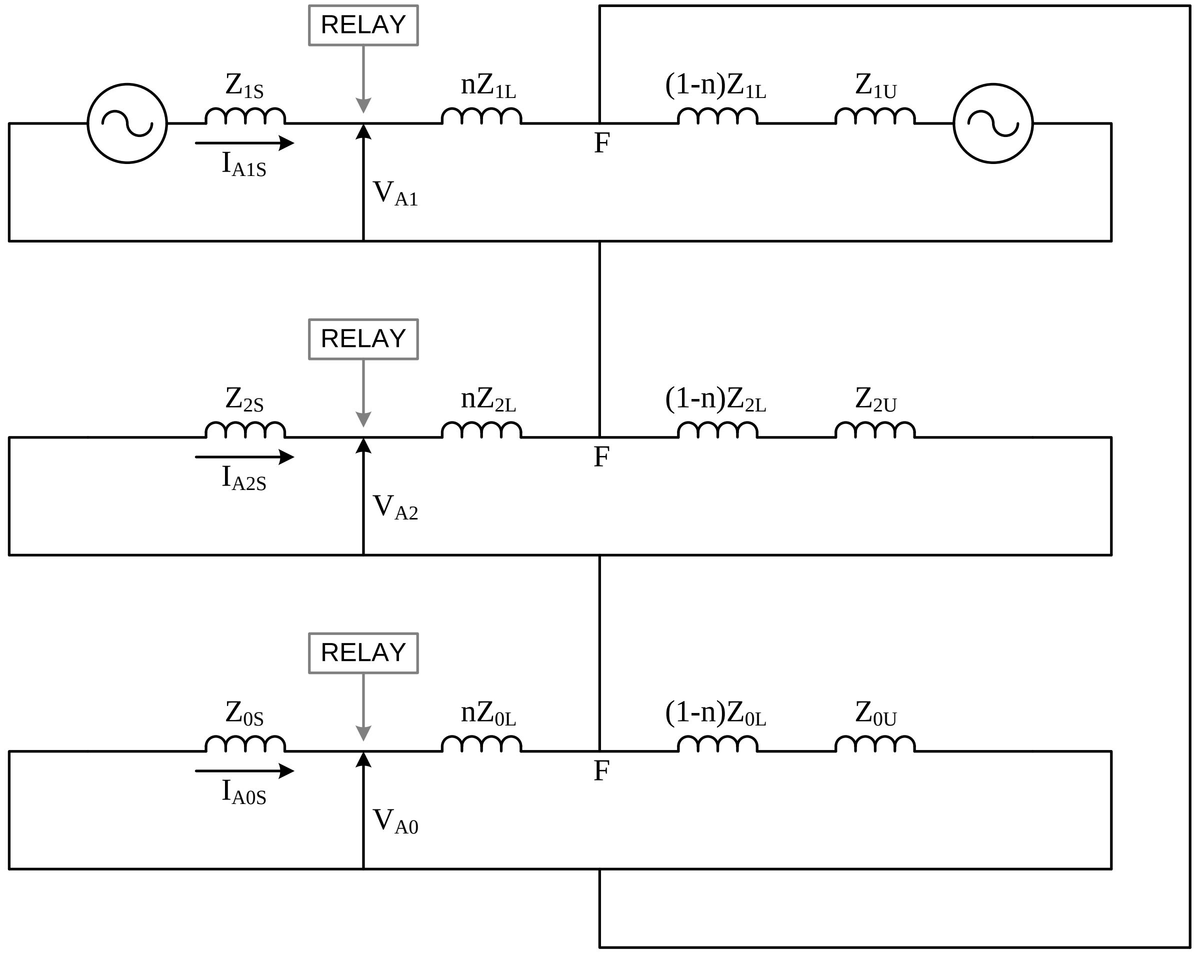


Figure 4.2.0: Sequence Network Connection for a Single-Line to ground fault

Relay Sequence Voltage

Figure 4.2.0 shows the sequence network connection for a single-phase to ground fault on a line "n" distance away from the relay location. From the fault location each sequence network can be reduced into the simplified representation shown in Figure 4.2.1. Using zero sequence or negative sequence voltage for polarizing, the maximum voltage can be estimated from Figure 4.2.1. It is seen that the nature of the fault dictates the voltage that is available in the two networks. The maximum zero and negative sequence voltages appear at the fault point. This is not surprising because the fault is the source of these voltages. Letting Z0, Z1, and Z2 be the total impedance looking from the fault into each of the three networks, and assuming Z1 = Z2, then:

$$V_{A0} = \frac{Z_0}{(Z_0+2Z_1)} \quad \text{Eq. 4.2.1}$$

$$V_{A2} = \frac{Z_1}{(Z_0+2Z_1)} \quad \text{Eq. 4.2.2}$$

Putting this in a more useful form:

$$V_{A0} = \frac{Z_0/Z_1}{\left(Z_0/Z_1 + 2\right)} \text{ per unit} \qquad \text{Eq. 4.2.3}$$

$$V_{A2} = \frac{1}{\left(Z_0/Z_1 + 2\right)} \text{ per unit} \qquad \text{Eq. 4.2.4}$$

From this, the levels of these quantities at the fault can be estimated, knowing only the ratio of the system impedances without knowing their actual values. On a typical well-grounded system, this ratio will be three or less. V0 will then be 60 % or less of rated voltage and V2 will be 20 % or more.

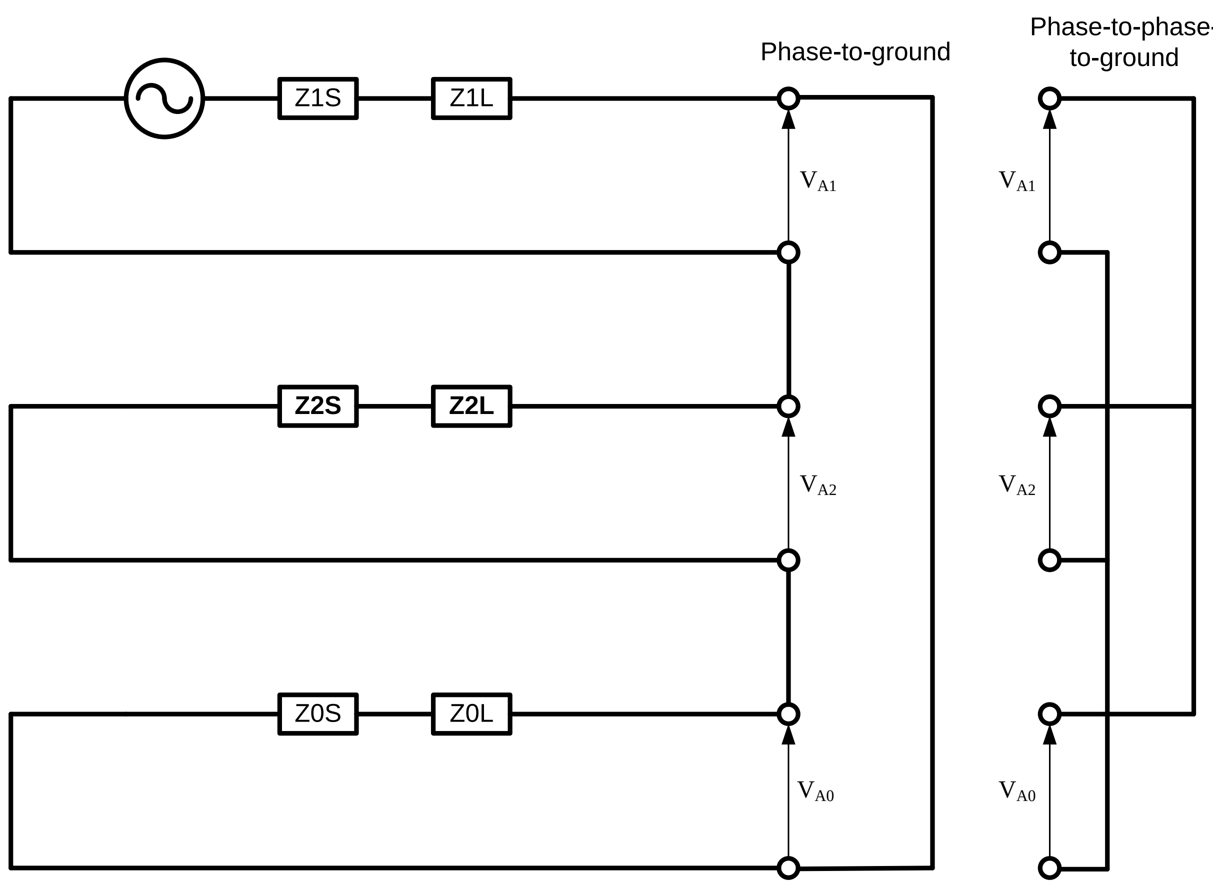


Figure 4.2.1: Phase-to-ground Fault Connections

Figure 4.2.1 also shows, at the right, the connection for a phase-to-phase-to-ground fault. At the fault the positive, negative and zero sequence voltages are identical. Their value is:

$$V_{A0} = \frac{Z_0/Z_1}{\left(2Z_0/Z_1 + 1\right)} \text{ per unit} \qquad \text{Eq. 4.2.5}$$

Figure 4.2.2 shows how the magnitude of the sequence voltages vary with the fault type and the Z0/Z1 ratio as viewed from the fault point. From this standpoint, V2 would clearly be the preferred choice as a polarizing source for systems with a ratio less than 1. Similarly, for systems having a higher ratio, V0 would be preferred, if this were the only consideration.

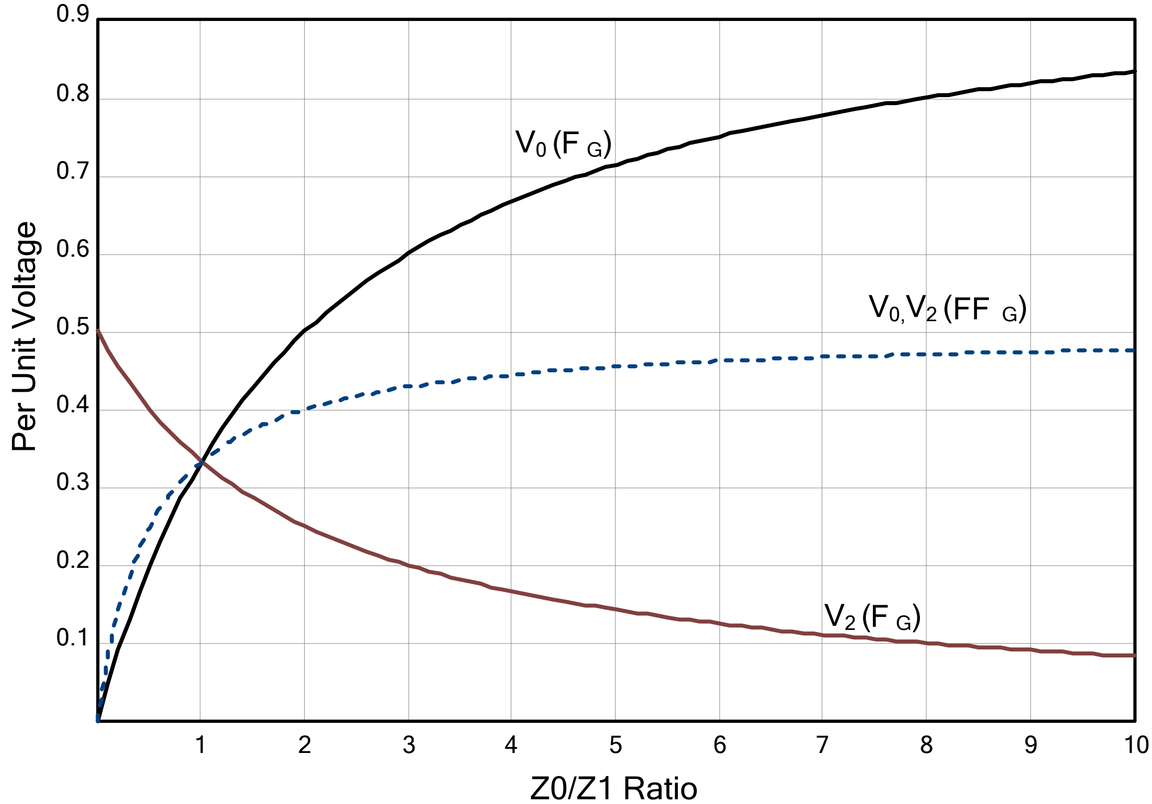


Figure 4.2.2: V0 and V2 at the Fault vs. Z0/Z1 Ratio

Going back to Figure 4.2.0, it can be seen that the voltage at the fault is not the same as the voltage at the relay. Also the voltage drops in the line for negative-sequence current and for zero-sequence current are quite different. Zero sequence line impedance is roughly three times that of negative sequence.

If the system is homogeneous, that is, if the ratios of source to line impedances are similar in the zero and negative sequence networks then the ratios of voltages at the relay will be the same as at the fault. Clearly, then, from the standpoint of energy level, if voltage is to be used to polarize the ground relays, zero sequence polarizing is superior.

Where the system is not homogeneous, a comparison of the relative zero and negative sequence voltages still can be estimated easily. See Figure 4.2.0.

$$V_{A0R} = V_{A0F} - I_{A0R} n Z_{0L} \qquad \text{Eq. 4.2.6}$$

This can be written as:

$$V_{A0R} = V_{A0F}\left(1 - \frac{nZ_{0L}}{Z_{0S}+nZ_{0L}}\right) \qquad \text{Eq. 4.2.7}$$

then,

$$V_{A0R} = V_{A0F}\left(\frac{Z_{0S}}{Z_{0S}+nZ_{0L}}\right) \qquad \text{Eq. 4.2.8}$$

and,

$$V_{A0R} = V_{A0F}\left(\frac{1}{1+{}^{nZ_{0L}}/_{Z_{0S}}}\right) \qquad \text{Eq. 4.2.9}$$

where: V_{A0R} = zero-sequence voltage at the relay (per-unit)
V_{A0F} = zero-sequence voltage at the fault (per-unit)
nZ_{0L} = zero-sequence line impedance from the fault to the relay
Z_{0S} = zero-sequence source impedance

Similarly:

$$V_{A2R} = V_{A2F} - I_{A2R}nZ_{2L} \qquad \text{Eq. 4.2.10}$$

This can be written as:

$$V_{A2R} = V_{A2F}\left(1 - \frac{nZ_{2L}}{Z_{2S}+nZ_{2L}}\right) \qquad \text{Eq. 4.2.11}$$

then,

$$V_{A2R} = V_{A2F}\left(\frac{Z_{2S}}{Z_{2S}+nZ_{2L}}\right) \qquad \text{Eq. 4.2.12}$$

and,

$$V_{A2R} = V_{A2F}\left(\frac{1}{1+{}^{nZ_{2L}}/_{Z_{2S}}}\right) \qquad \text{Eq. 4.2.13}$$

where: V_{A2R} = negative-sequence voltage at the relay (per-unit)
V_{A2F} = negative -sequence voltage at the fault (per-unit)
nZ_{2L} = negative -sequence line impedance from the fault to the relay
Z_{2S} = negative -sequence source impedance

Finally, taking the ratio of these two quantities and substituting: Z1=Z2 (the total sequence network impedances as viewed from the fault point) and for the phase-to-ground fault, VA0F/VA2F=Z0/Z2, we get:

$$\frac{V_{A0R}}{V_{A2R}} = \frac{Z_0}{Z_2}\left(\frac{1+{}^{nZ_{1L}}/_{Z_{1S}}}{1+{}^{nZ_{0L}}/_{Z_{0S}}}\right)(\Phi G) \qquad \text{Eq. 4.2.14}$$

This is a completely generalized expression and can be used to evaluate the relative levels of the polarizing voltages that will be available at the relay for a line to ground fault at any point along the line. For phase-to-phase-to-ground faults, the generalized equation is:

$$\frac{V_{A0R}}{V_{A2R}} = \left(\frac{1+{}^{nZ_{1L}}/_{Z_{1S}}}{1+{}^{nZ_{0L}}/_{Z_{0S}}}\right) \quad (\Phi\Phi G) \qquad \text{Eq. 4.2.15}$$

Note that these two equations apply, irrespective of what system components exist to the right of the fault point and irrespective of the relative sequence-current distribution factors. Those other system components will, of course, influence the total Z0 and Z1 values, but their ratio will not vary greatly.

From these two expressions above, it can be seen for long line applications that polarizing voltage level, as a criterion, may favor zero-sequence voltage polarizing, because Z0L usually exceeds Z1L.

For short-line applications, the ratio of the sequence voltages at the relay will be more nearly that which exists at the fault, thus favoring the use of zero-sequence voltage polarizing.

Polarizing Voltage Magnitude

Referring to Figure 4.2.0, it can be seen that the magnitude of the negative- or zero-sequence voltages are directly proportional to the current and the source impedance behind the relay location. Therefore, it can be seen that given a long line with a strong source behind the relay ($Z_{2L} >> Z_{2S}$ or $Z_{0L} >> Z_{0S}$) the negative or zero-sequence voltage at the relay location can be relatively small. Although the previous analysis indicated that zero-sequence is a better choice for long line applications, we can see that it is also dependent upon the strength of the source behind the relay.

When evaluating the choice of negative or zero-sequence voltage polarization for long lines there are two factors that will influence the decision; the magnitude of the negative- or zero-sequence voltage at the fault and the ratio of the negative- or zero-sequence lines impedance to the respective source impedance behind the relay location. The magnitude of the sequence voltage at the fault can be determined using Eq. 4.2.3 and Eq. 4.2.4 for the respective sequence voltage. The magnitude of the voltage at the relay location can be determined from Eq. 4.2.9 and Eq. 4.2.13. Combing these equations and recognizing that the critical fault location is going to be at the remote end of the line where n = 1 (refer to Figure 4.2.0), we get:

$$V_{A2R} = \left(\frac{1}{Z_0/Z_1+2}\right)\left(\frac{1}{1+Z_{2L}/Z_{2S}}\right) \text{ per unit} \qquad \text{Eq. 4.2.16}$$

$$V_{A0R} = \left(\frac{Z_0/Z_1}{Z_0/Z_1+2}\right)\left(\frac{1}{1+Z_{0L}/Z_{0S}}\right) \text{per unit} \qquad \text{Eq. 4.2.17}$$

where:
- V_{A2R}, V_{A0F} = negative- and zero-sequence voltage at the relay (per-unit)
- Z_{2L}, Z_{0L} = negative- and zero-sequence line impedance
- Z_{2S}, Z_{0S} = negative and zero-sequence source impedance
- Z_0 = total zero-sequence impedance at the fault
- Z_1 = total positive-sequence impedance at the fault

Equations 4.2.16 and 4.2.17 are representative of Eq. 4.2.15 but instead of providing the ratio of V_{A0R} to V_{A2R}, Eq. 4.2.16 and Eq. 4.2.17 provide the magnitude of each sequence voltage that can then be compared to protective relay operating characteristics and expected error from the power system or instrument transformers.

For example, if a protective relay requires a minimum negative-sequence voltage of 1V secondary, we can check the magnitude of V_{A2R} using Eq. 4.2.16 against this threshold from data obtained from a fault study and the line parameters. If the voltage obtained from Eq. 4.2.16 is less than 1V secondary, then negative-sequence polarization would not be a good choice for this application.

Sources of Error in calculating V_2 and V_0 – Untransposed Lines

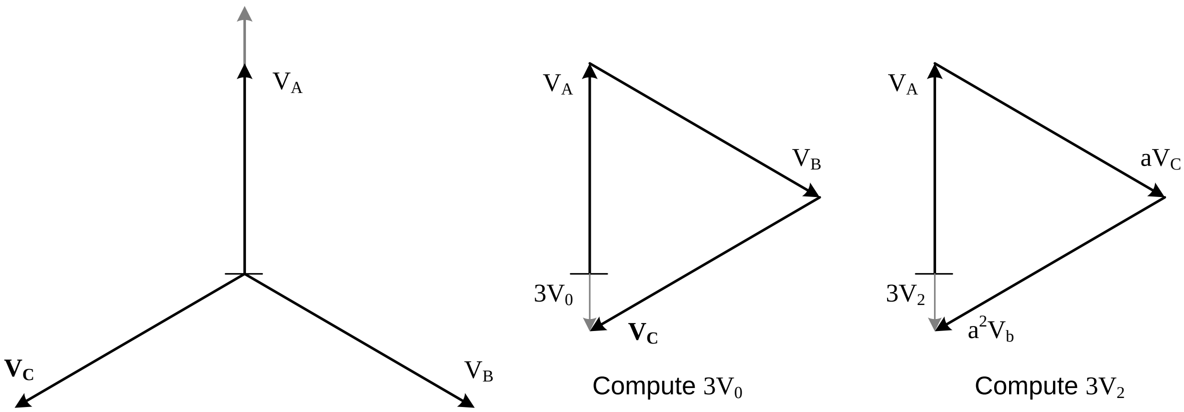
Errors caused by untransposed lines can result in an erroneous negative- or zero-sequence voltage during steady-state conditions. If these error voltages are greater than the fault generated voltages, then the polarizing voltage could reverse resulting in an incorrect directional decision.

Lack of transpositions on long transmission lines causes the phase impedances to be unequal. Thus a three-phase fault, for example, will generate zero and negative-sequence voltage drops. This, in turn, causes zero and negative-sequence current flow that may be of sufficient magnitude to produce undesirable operation of directional ground overcurrent relays. It is reasonable to attribute the following problem to unequal phase impedances.

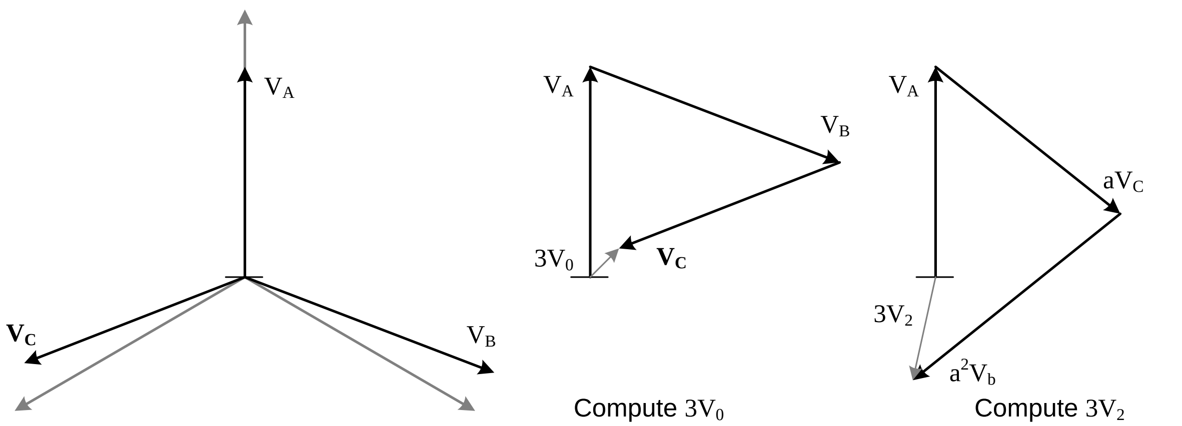
Directional units based on symmetrical component theory depend on reasonably stable balanced three phase voltages and that during the fault condition, non-faulted phases are not appreciably affected. This is essential if we are to rely on zero and negative sequence voltages as polarizing voltages for ground directional units. During the analysis of directional unit operations for single phase-to-ground faults unbalances in the non-faulted phases have been observed. The source of the unbalance is not certain, but is expected to be the result of unbalanced phase impedances and loading. In some cases of low sensitivity (very remote faults) these unbalanced voltages have caused a reversal of the polarizing voltage resulting in incorrect directional sensing. This effect is illustrated in Figure 4.2.3.

Figure 4.2.3(a) shows the expected phase and sequence voltages for a phase AG fault. The negative- and zero-sequence voltages are graphically computed using the symmetrical component equations:

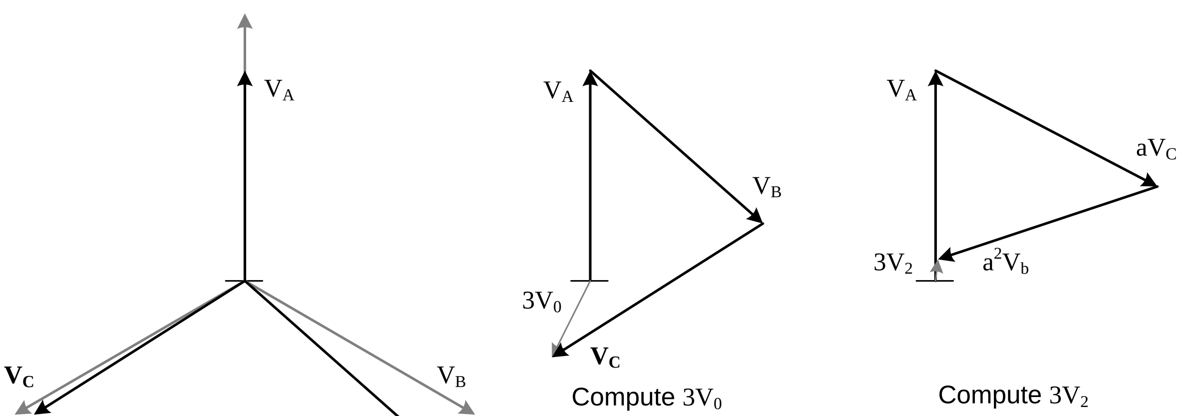
$$3V_0 = V_A + V_B + V_C$$
$$3V_2 = V_A + a^2V_B + aV_C$$



(a) Normally Expected Phase and Sequence Fault Voltages



(b) Phase and Sequence Fault Voltages Showing Reversal of $3V_0$



(c) Phase and Sequence Fault Voltages Showing Reversal of $3V_2$

Figure 4.2.3: The Effect of Unbalanced Phase Voltages on Voltage Polarization

Figure 4.2.3(b) shows the direction reversal of $3V_0$ where the phase angle between the unfaulted phases is greater than 120°. Figure 4.2.3(c) shows the direction reversal of $3V_2$ where the phase angle between the unfaulted phases less than 120°. This unbalance, although small, introduces enough effect on the “expected" sequence voltage angle at these small values causing the incorrect directional sensing.

4.3 Combining multiple polarizing methods

Several methods exist for combining polarizing methods:

4.3.1 Dual zero-sequence polarizing

Both zero-sequence voltage and zero-sequence current are used. Different ways of implementing this include:

- Sum of torque developed using each method
- If zero-sequence polarizing current is above a certain threshold (e.g., 0.5A secondary), only zero-sequence current polarizing is used, neglecting any decision made or torque developed by the zero-sequence voltage element. If the zero-sequence current is below the threshold, then the zero-sequence voltage element is used.

4.3.2 Both negative and zero-sequence polarizing (preferential based on sensitivity thresholds)

Some relays have the capability of implementing zero-sequence voltage, zero-sequence current, and negative sequence polarizing, giving preference to any order of the three, based on meeting sensitivity thresholds.

Caution should be used when implementing such a scheme. If zero-sequence polarizing is an inadequate method (say, due to mutual coupling), it generally should not be combined with negative-sequence polarizing even if the relay provides that capability.

5.0 Other Considerations

5.1 Installation and verification tests of the directional elements

To avoid misoperation of ground relaying, polarizing circuits should be checked before the relays are placed in service. Many utilities have testing guidelines on how to verify the polarizing methods. Guidance can also be obtained from IEEE Std. C37.103 Guide for Differential and Polarizing Relay Circuit Testing.

With the advent of microprocessor relays with digital oscillographic capability, another option may be considered for polarizing methods using dual zero-sequence polarizing. It would be possible to initially place a relay in-service with voltage polarizing only (zero or negative sequence), then examine the first oscillographic record taken for a nearby phase-ground fault (in-service polarizing test). Since voltage polarizing is determined internally, it should operate properly. Current polarizing connections to the relay could be determined by examining the relay record and corrected if necessary. Then current polarizing could be enabled. This method has been used in practice in a few locations due to the difficulty in performing current polarizing tests, particularly at large generating stations.

5.2 Open pole conditions

5.2.1 Single pole open condition affecting an adjacent line [7], [8]

While the effects of a pole open are most noticeable on the line with the pole open it also presents a concern for adjacent lines. Transmission lines using single-pole tripping invariably have pilot protection schemes that allow both ends to know of the open pole condition. This allows those relays to disable elements that may be susceptible to misoperation during the open pole condition. Relays on adjacent lines do not have this luxury; as a result careful consideration should be given to the operation of directional elements on these adjacent lines. Factors such as load flow, directional sensitivity, and target resistive coverage will effect implementation. Due to the complexity of the problem some solutions may be ineffective under different system conditions and desensitizing fault detectors to avoid misoperation on the open-pole may reduce the resistive coverage to the point that these elements aren't particularly useful in the first place.

With modern communications capabilities it may be possible to allow traditional sensitive directional ground TOC elements to remain operational, only being disabled when commanded from a local or remote relay. This of course adds complexity which must be weighed against the perceived benefits.

Below is an example of polarizing quantity under a single pole open condition for a SLG fault depicted in the figures below:

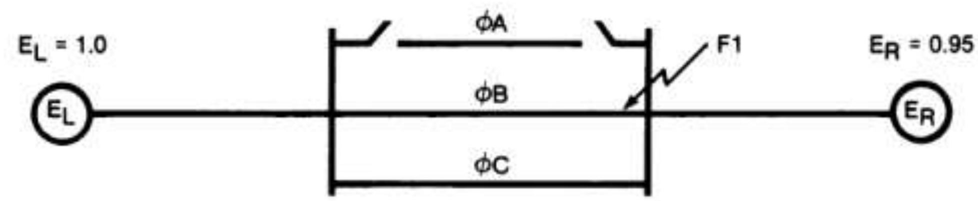


Figure: 5.2.0: A Phase Pole Open; B Phase Single-Line-to-Ground at the Remote Bus

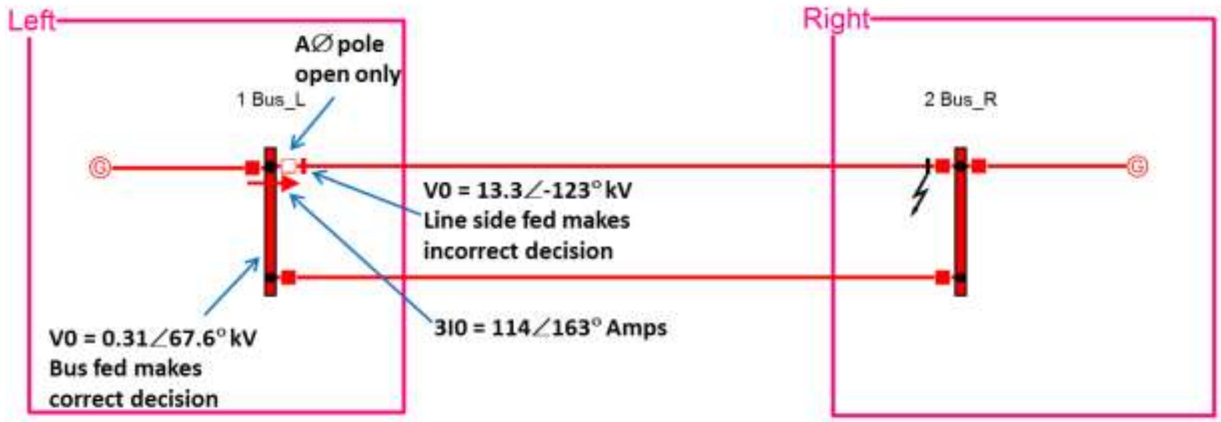


Figure: 5.2.1: Zero Sequence Components at the Local Terminal

The sequence voltage polarizing quantities at Bus_L are:

```
Substation Left
Bus      1 Bus_L         Base kV  161.00 Ph-Ph (92.95 @0 deg A-Gnd)
                         Prefault 1.000 V (p.u.)   @    0.00
                              + seq             - seq          0 seq / 3Io
                         ---------------    ---------------   ---------------
Voltage (kV) Ph-Gnd  > 89.7910 @   0.3    3.25179 @ -50.4    0.30549 @  67.6
Fault Currents (Amps)> 114.469 @-105.3    119.588 @  56.1    114.086 @ 163.0
```

The sequence voltage polarizing quantities at line side of the open A phase pole are:

```
Substation Left
Bus 999001 Bus_L         Base kV  161.00 Ph-Ph (92.95 @0 deg A-Gnd)
                         Prefault 1.000 V (p.u.)   @    0.00
                              + seq             - seq          0 seq / 3Io
                         ---------------    ---------------   ---------------
Voltage (kV) Ph-Gnd  > 83.1582 @  -7.6    14.8597 @-110.8    13.2505 @-123.1
Fault Currents (Amps)> 114.469 @  74.7    119.588 @-123.9    114.086 @ -17.0
```

Recall from Section 3 for zero sequence voltage polarizing, from Figure 3.2.1 the directional torque produced by an example electromechanical relay has the following directional ground torque equation:

$$MPP = \frac{E_P \cdot I_0 \cdot COS(\theta - 60°)}{3.6}$$ where θ is the angle by which I_0 lags E_P.

For a relay with line side potential polarizing source,

$$E_P \approx -3V0 = 13.25\angle(180° - 123°)\ kV = 13.25\angle 57°\ kV$$

Then the angle by which I_0 lags E_P is $\theta = 360° - (163° - 57°) = 254°$. This results in a negative torque, $COS(254° - 60°) = -0.97$, which is incorrect directional decision relative to the fault.

5.3 Modeling of ground directional element in software

Software programs employ both generic methods (for example, classic methods for zero- and negative-sequence polarization) as well as manufacturer specific methods of polarization. The user should be cognizant of the difference. A generic model may not properly identify the relay polarizing sensitivity whereas a manufacturer specific model will. If the manufacturer's specific models exist, the relay type name tells you whether or not it is manufacturer specific; that is, each of the manufacturer specific relay type names includes the corresponding model number. These programs provide the applicable setting ranges and choices for the manufacturer specific relay models. Programs use steady-state phasors for the polarizing circuits as well. [9], [10], [11], [12], [13]

5.4 Special considerations for series compensated lines or lines near series compensated lines and static var compensator

When series compensation is applied to transmission lines, it is possible for ground directional overcurrent elements to misoperate. Figure 5.4.0 shows a typical bypass arrangement for a series compensated line. During a fault the high level of current drawn through the transmission line causes a high voltage drop across the capacitor. This high voltage causes the metal oxide varistors (MOVs) to conduct fully eliminating the high voltage. In the case where the MOVs conduct fully, the capacitance is effectively in parallel with a short circuit, removing the impact of the series capacitor. If the MOVs fully conduct as previously described, the ground directional elements will typically operate satisfactorily. However, in cases where low magnitude fault currents occur, for example a high resistance ground fault, the MOVs will only partially conduct. This leads to some amount of capacitance remaining in the line.

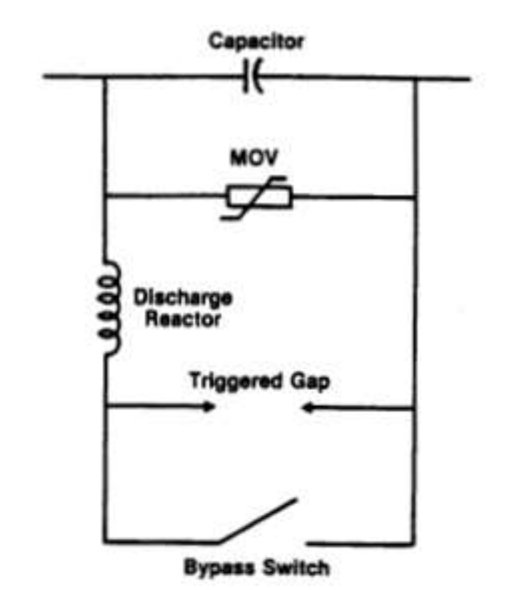


Figure 5.4.0: Typical Series Capacitor and Bypass Arrangement

During partial MOV conduction, the equivalent capacitance that remains can cause voltage and/or current "inversions". In this phenomenon, the voltage drop due to the remaining capacitive reactance on the line is significant enough to counteract the voltage drop across the inductive reactance of the line. This inversion can be significant enough to reverse the polarizing quantities for zero sequence or negative sequence directional elements at one of the line terminals leading to an incorrectly defined fault direction.

To address these potential inversions, modern microprocessor relays utilize some variety of impedance compensation. The directional elements are set with an offset impedance or other compensation factor that assumes the series capacitance remains in the transmission line. This equivalent impedance is then used to bias the ground directional element in such a way to ensure proper directional element operation even when the series capacitance remains in the circuit.

5.4.1 Impact of the sub-synchronous frequency component on the operation of directional elements applied to series-compensated transmission lines

On series-compensated transmission lines, a transient sub-synchronous component with a frequency typically in the interval of 5 to 20 Hz will be generated every time a change occurs on the line and will be reflected in the measured line three-phase voltages and currents. This change could simply be a change on the network like the switching of an apparatus or a line fault. This transient sub-synchronous frequency is due to the electrical interaction of the series capacitor and the line reactance together with any existing power shunt reactor at the line extremities. The ensuing resonant circuit will determine the frequency of the transient oscillation.

A directional element can simply be looked at as an element that evaluates the phase angle between an operating quantity phasor and a polarizing quantity phasor. Very often, the direction is determined by way of a phase comparator by looking at the phase angle between the two quantities. Mathematically, a simple scalar product will do the work. A positive scalar product indicates a forward fault corresponding to the angle between the two phasors being smaller than 90˚. A negative scalar product indicates a reverse fault corresponding to the angle between the two phasors being greater than 90˚.

When the waveforms from which the phasors are derived are essentially at the fundamental frequency of 60 Hz, the phase angle between the operating and polarizing phasors will be constant during the fault so that the direction indicated by the directional element will be stable and will not change. If however a sub-synchronous frequency component appears in the operating or the polarizing waveform, the corresponding phasor will start rotating at a rate corresponding to the sub-synchronous frequency. Because of this rotation in one of the phasors, the phase angle between the two phasors involved in the scalar product will no longer be constant and a succession of changes in the direction provided by the element could be observed. In other words, there could be a loss of directionality during the fault.

It is difficult to predict in advance if a directional element of some type will work properly with a given series-compensated transmission line. Any protection scheme has to be evaluated by proper and extensive testing as it is usually applied every time a series-compensated line has to be dealt with.

5.5 Inherently directional; strong source impedance behind and weak forward source impedance

In some applications, it is possible that the power system network configuration is such that directional control of a ground overcurrent function may not be necessary. These applications are primarily those in which the network configuration is such that the zero sequence current contribution from the line to short circuits in the reverse direction is small enough to be negligible. In these cases, directional control of ground overcurrent functions may be unnecessary and in some cases, even undesirable.

The most obvious example is that of a radial circuit without any significant path for zero sequence current on the protected circuit. An example is a subtransmission line with only transformers with delta connected windings connected to it, as shown in Figure 5.5.0.

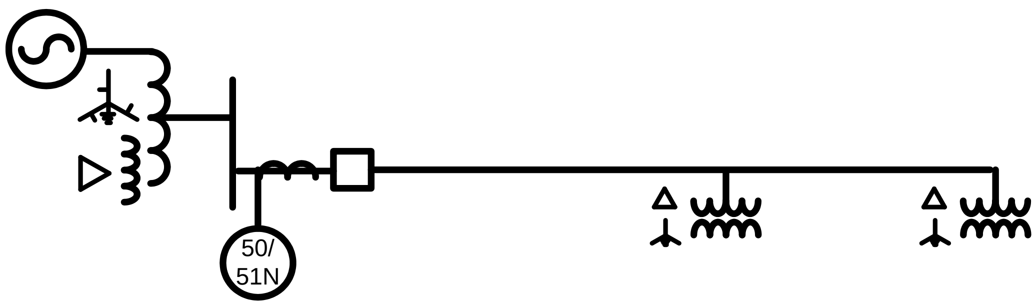


Figure 5.5.0: Radial sub-transmission system with no remote path for ground current

Since there will be no zero sequence current contribution to a ground fault behind the line terminal there will be no need for directional ground overcurrent protection. This is simply an extreme case of a system configuration that is inherently directional.

Another less obvious, but similar case could be two subtransmission circuits looped at a remote substation without any path for zero sequence currents except at the source as shown in Figure 5.5.1.

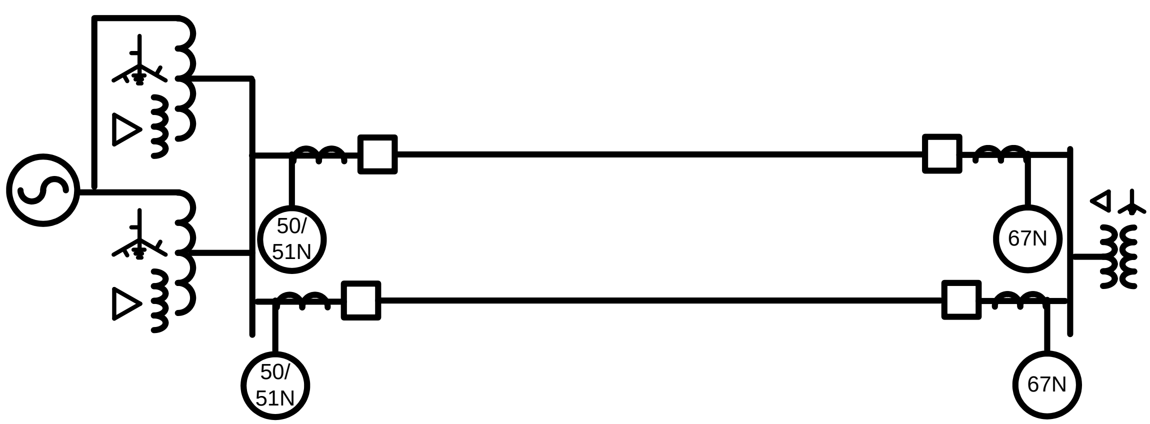


Figure 5.5.1: Looped sub-transmission system with no remote path for ground current

In the case of Figure 5.5.1, there is no need for directional ground overcurrent relays at the line terminals on the left side of the figure. Of course there may well be a need for directional ground overcurrent relays at the line terminals on the right side of the figure.

Similar to the case of Figure 5.5.0, the network configuration is such that the relays on the left terminal are inherently directional, and additional directional control is not required.

Following on from the relatively obvious cases shown in Figures 5.5.0 and 5.5.1, the next case is that of a line that is so long that the zero sequence current contribution from the remote terminal to faults behind the local terminal may be small enough to allow the use of non-directional overcurrent protection. IEEE Standard C37.113 defines a long line as one in which the source to line impedance (SIR) ratio is less than 0.5. Consider a system such as the one shown in Figure 5.5.2

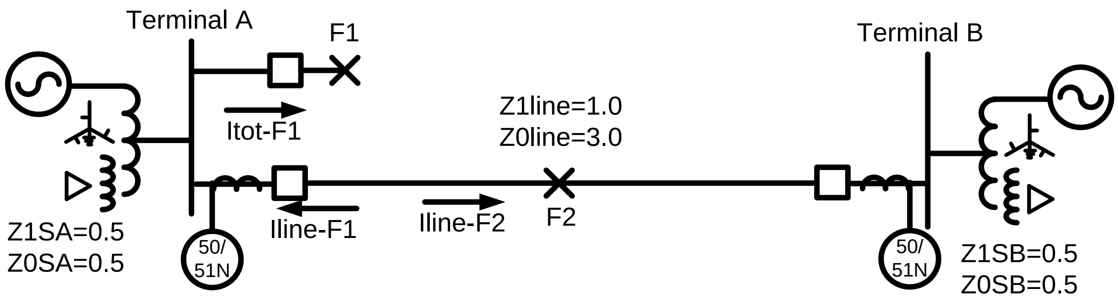


Figure 5.5.2: Long line and two fault locations

The impedances shown in the figure are in per unit. They correspond to a value of 0.5 for SIR. The figure further assumes the positive and zero sequence source impedances at both terminals are equal to each other and the zero sequence line impedance is equal to three times the positive sequence line impedance. Using these values, (and assuming no mutual coupling to parallel lines), it can be calculated that for a fault at location F1 with negligible fault impedance,

Itot-F1=2.53 pu and Iline-F1=0.316 pu.

Therefore, the zero sequence current contribution from the remote terminal to a reverse fault is approximately 12% of the total zero sequence current to the fault. Thus a non-directional ground overcurrent element could be set to operate at about 0.4 pu, or 15% of the total zero sequence current to a close-in forward fault without any danger of undesired operation for a close-in reverse fault.

For a fault at location F2, with negligible fault impedance, it can be calculated that

Iline-F2=0.75 pu. Therefore a non-directional overcurrent element could sense zero ohm short circuits on significantly more than 50% of the line while the remote terminal is closed.

For a fault at the right hand end of the line, with the remote terminal open, the total fault current seen by the relay would be approximately Iline-LE=0.46 pu.

Therefore, the non-directional overcurrent will sense a fault on 100% of the line sequentially, assuming the remote terminal opens first for faults beyond the 50% point. Further, the time current characteristic of a non-directional time overcurrent element would be shifted to the right by a factor of approximately 12 when compared to time current characteristics on adjacent circuits. Thus a non-directional time overcurrent element may also be applicable. Whether or not the underreaching non-directional instantaneous overcurrent function together with the non-directional time overcurrent function will be sufficient for the application will depend very much on the specific circumstances. However, it is possible that in the case of lines with SIR significantly lower than 0.5, non-directional time and instantaneous overcurrent protection may be adequate.

Some factors to consider when applying non-directional ground overcurrent protection on a long line are as follows:

Can the SIR change so that the line zero sequence current contribution from the remote terminal is no longer small under certain circumstances? For instance could the situation of Figure 5.5.1 change to that of Figure 5.5.3 under any circumstances? In the case of Figure 5.5.3, non-directional ground overcurrent relays at the left side terminals might not be suitable.

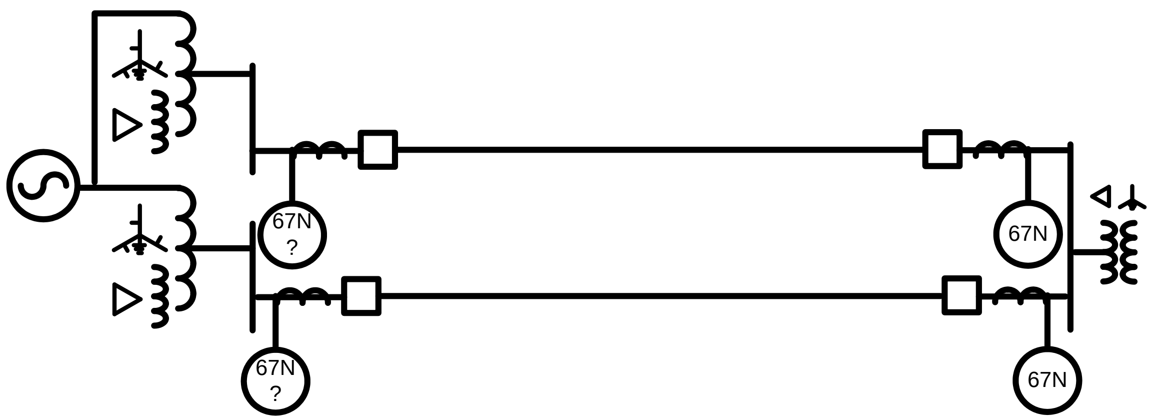


Figure 5.5.3: Configuration change to network of Figure 5.5.1 creates possible need for directional function

Does the status of a parallel line change such that the zero sequence current contribution from the remote source to a reverse fault increases? For instance if a parallel mutually coupled line is out of service and grounded at both ends, the zero sequence current contribution from the remote terminal to a reverse fault could be significantly higher than if the parallel line was simply open at both terminals.

5.6 Mismatch of polarization methods on line terminals in communication assisted trip scheme

It is recommended to use the same polarizing quantities at all terminals of a line protected with directional comparison pilot scheme that compares the ground fault current direction from each terminal. The following example is provided to support the recommendation.

Using negative and zero sequence polarization at opposite line terminals

Consider a transmission line protected by a communication scheme providing ground overcurrent directional comparison and an external remote system fault occurs. This is illustrated in Figure 5.6.0. The scheme consists of a relay system [K] at bus F using zero sequence voltage and current for directional polarizing and a relay system [M] at bus H using negative sequence voltage and current for directional polarizing. In this example, both systems see the remote fault between Bus F and Bus G in the forward direction and undesirably trip the transmission line. The tripping results because of the different directional polarizing methods used at the line terminals and the fact that the negative and zero sequence current components are flowing in opposite directions in the line between Bus F and Bus H giving the appearance of an internal fault. This occurrence can easily be explained.

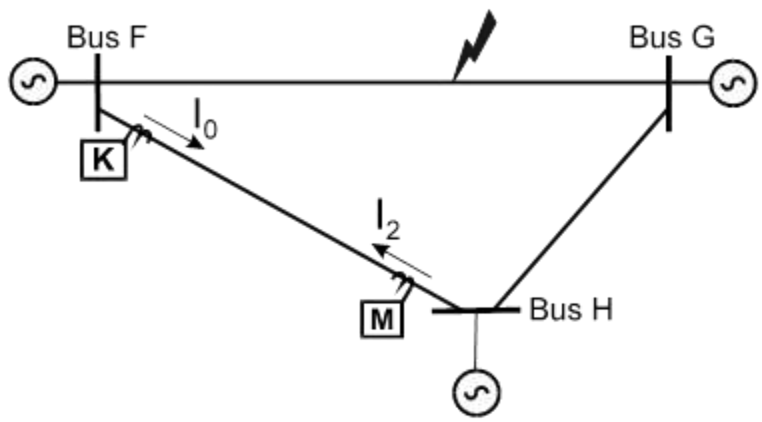


Figure 5.6.0: Simplified System Showing Relay and Fault Locations

Consider the sequence network with the impedance values as shown in Figure 5.6.1. The sequence networks are connected for a phase-to-ground fault on line FG. The electromechanical and microprocessor relays are protecting line FH. The positive and negative sequence impedances of line FG are 2.0 ohms. The zero sequence impedance is 6.0 ohms.

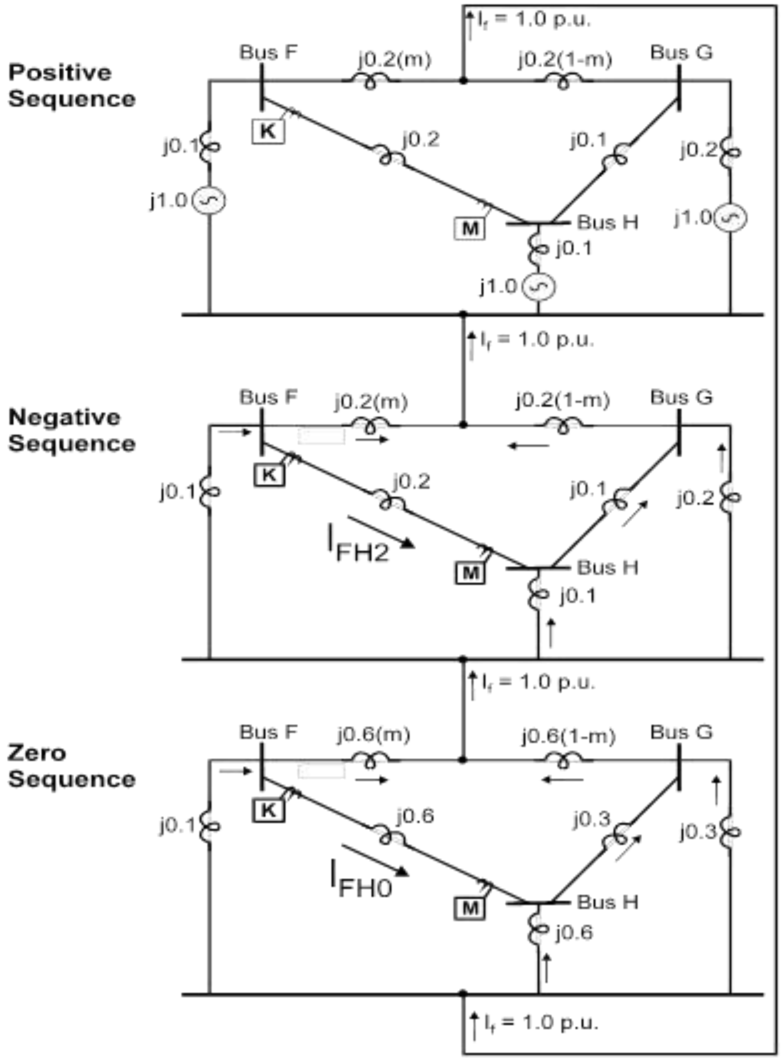


Figure 5.6.1: Sequence Networks for Sequence Coordination Study

To study the problem a phase-to-ground fault is applied at different points distributed along line FG from bus F to bus G, and the direction of the negative and zero sequence currents on line FH is monitored. The results are shown in Table 5.6.0 where **m** is the per unit length of the line from bus F and I_{FH2} and I_{FH0} are the negative and zero sequence currents (distribution factors) expressed in per unit of I_f.

Table 5.6.0. Sequence Currents on Line FH for Different Fault Locations on Line FG

m	**0**	**.1**	**0.2**	**0.3**	**0.4**	**0.45**	**0.5**	**0.6**	**0.7**	**0.8**	**0.835**	**0.9**	**1.0**
IFH2	-.196	-.173	-.149	-.125	-.102	-	-.078	-.055	-.031	-.007	0	.016	.039
IFH0	-.078	-.061	-.043	-.026	-.009	0	.009	.026	.043	.061	-	.078	.096

The results show that for these networks and impedances, the negative and zero sequence currents will flow in opposite directions on line FH for faults between 0.45 and 0.835 p.u. of line FG length as measured from Bus F.

This simple analysis shows the real potential for incorrect pilot tripping for ground faults when using different polarizing quantities at the line terminal relays. Therefore, the use of the same polarizing quantities at all line terminals for ground overcurrent directional comparison pilot applications is required.

5.7 Current polarizing at stations with more than one transformer and split low-sides

Some stations have more than one bank that could be used for polarizing. An interesting situation is presented for the station illustrated in Figure 5.7.0 (note the location of the CTs of the corresponding zero-sequence network in Figure 5.7.1):

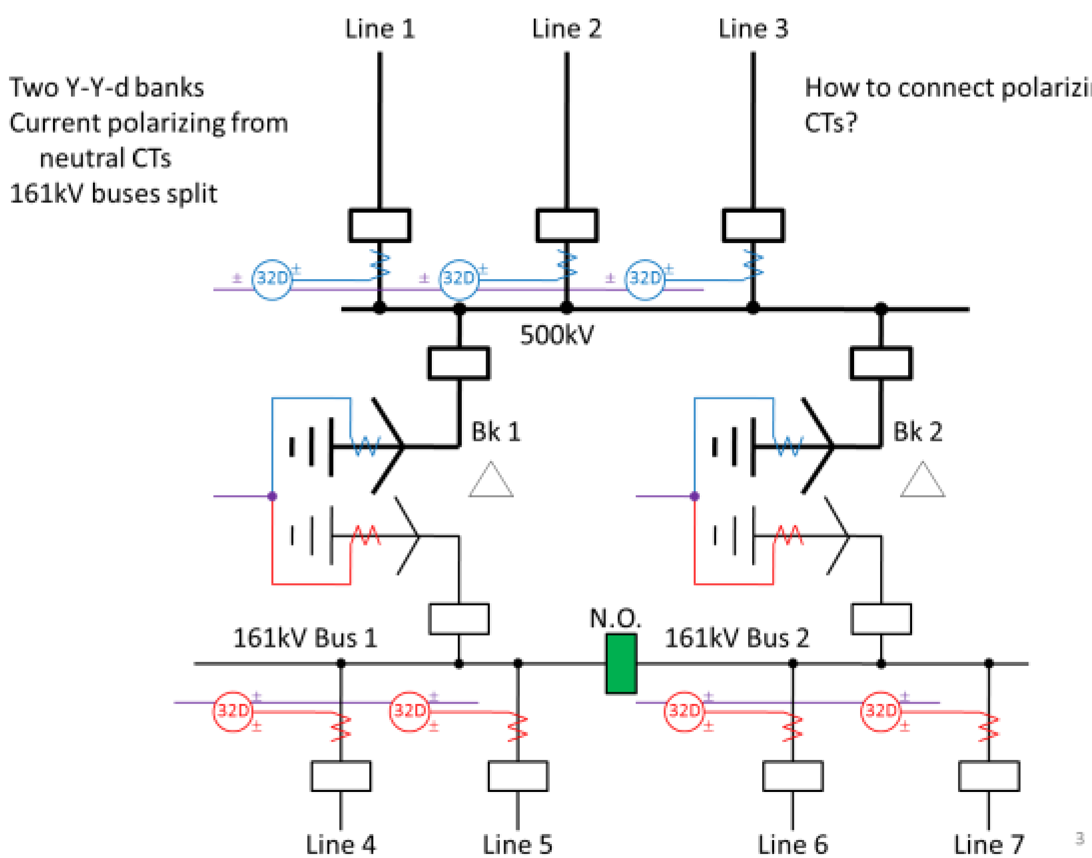


Figure 5.7.0: Station with two Y-Y-d banks, split low-sides

Zero-Sequence Network

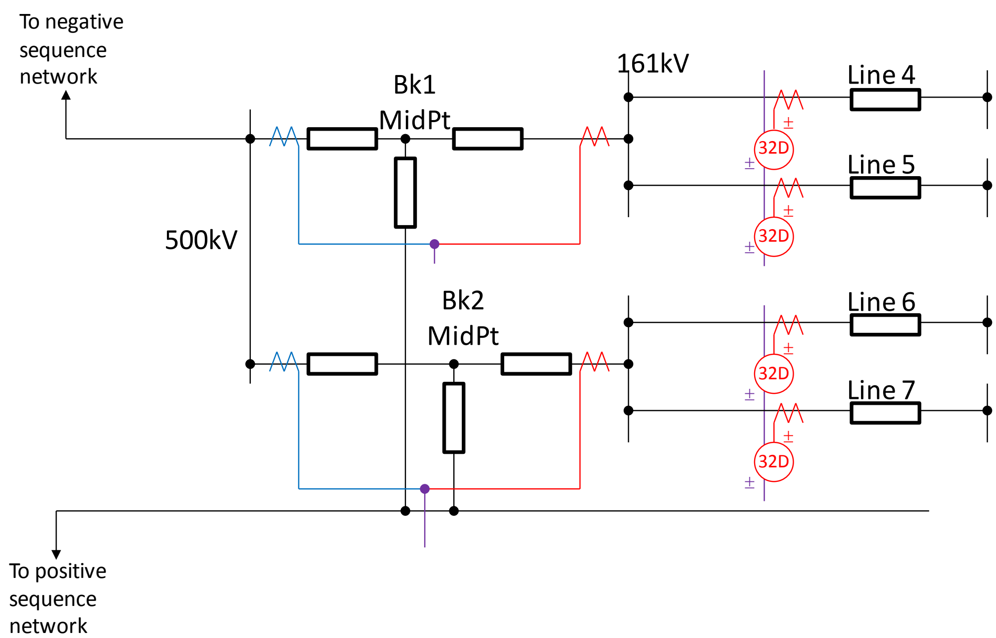


Figure 5.7.1: Zero-sequence network

In this station, a consideration is how to connect the polarizing currents to the line relays on Lines 4, 5, 6 and 7. One option is to connect only polarizing current from Bank 1 to the relays on Lines 4 and 5, and connect only polarizing current from Bank 2 to the relays on Lines 6 and 7. This is shown below in Figure 5.7.2 and the corresponding zero-sequence network in Figure 5.7.3.

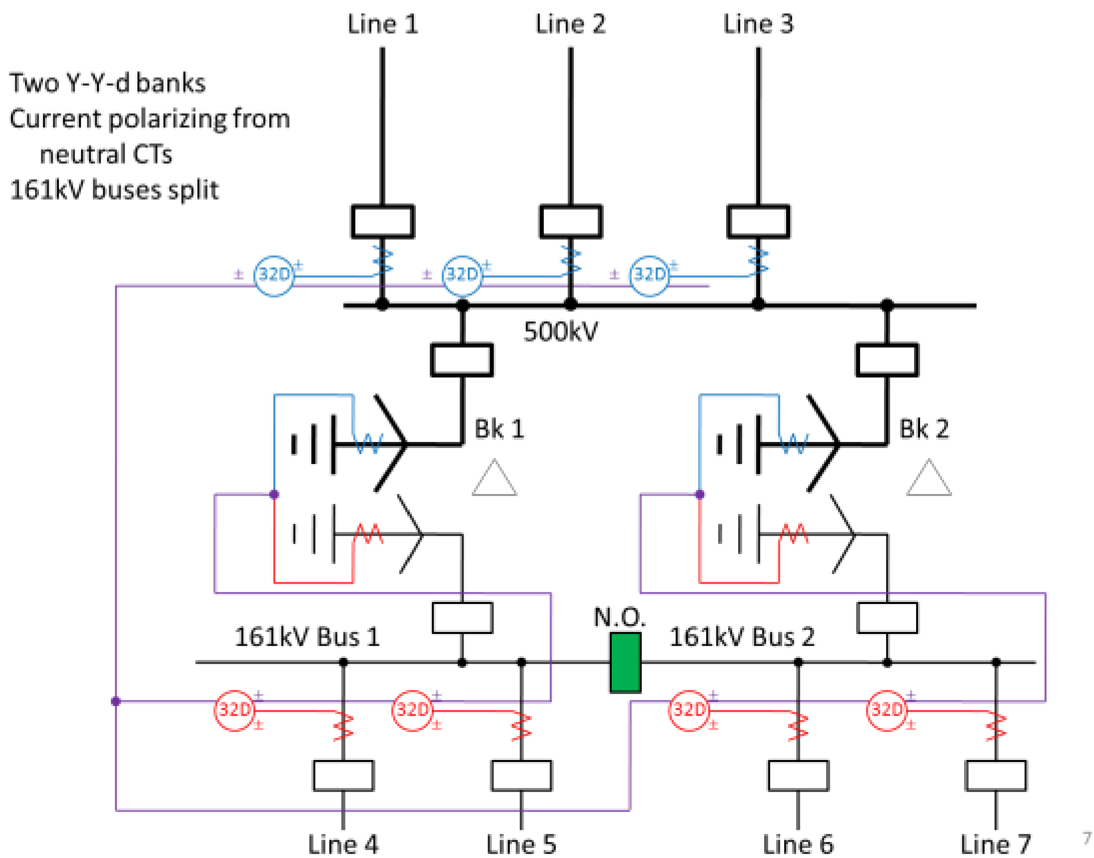


Figure 5.7.2: Each bank provides polarizing only to the 161kV lines it serves

Zero-Sequence Network

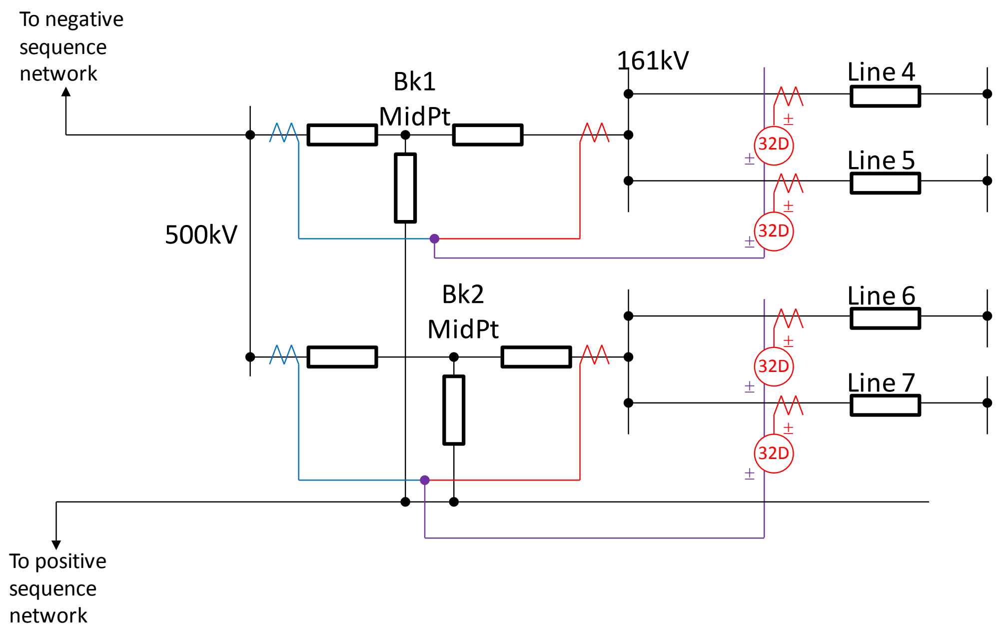


Figure 5.7.3: Zero-sequence network

This method would work as long as none of the lines have significant zero-sequence mutual coupling.

For example, in Figure 5.7.4, Line 4 has heavy mutual coupling with Line 6. For a fault on Line 4, Line 6 makes an incorrect forward decision if only Bank 2 polarizing current is used. This could result in a misoperation of Line 6 at both ends since the relays at the remote end would correctly see a forward fault.

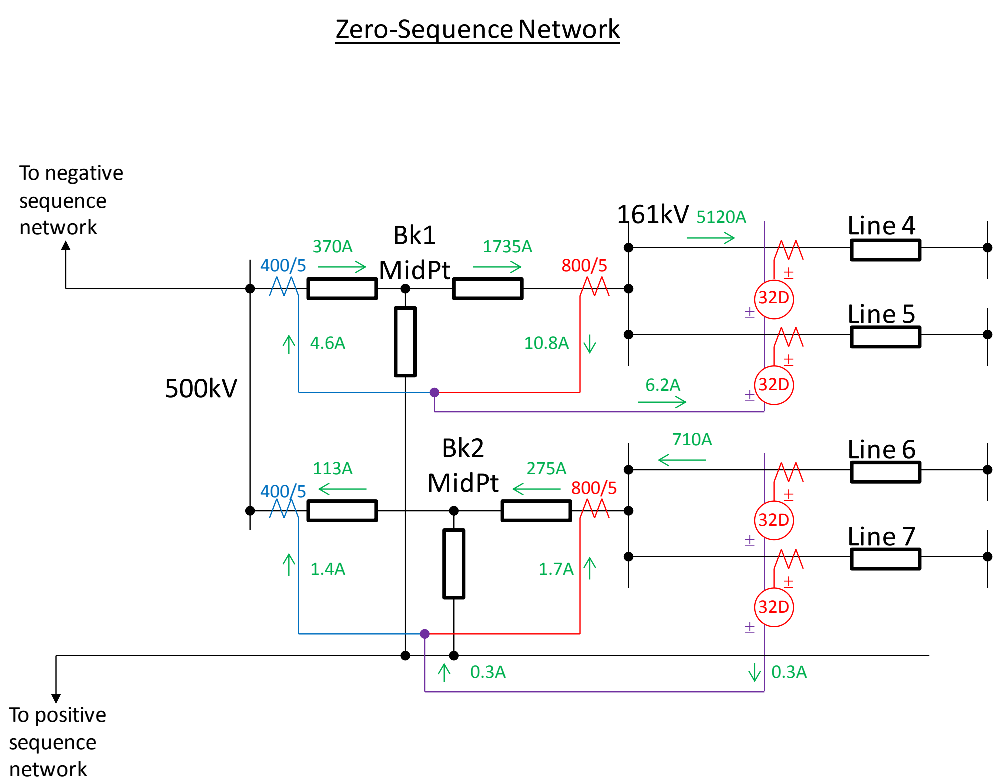


Figure 5.7.4: Line 6 polarized only from Bank 2, incorrect forward decision for fault on Line 4

An alternative method is to sum the polarizing currents from both Banks 1 and 2, and use the sum to polarize the relays on all lines (4-7). If this is done, Line 6 relaying would make a correct reverse decision:

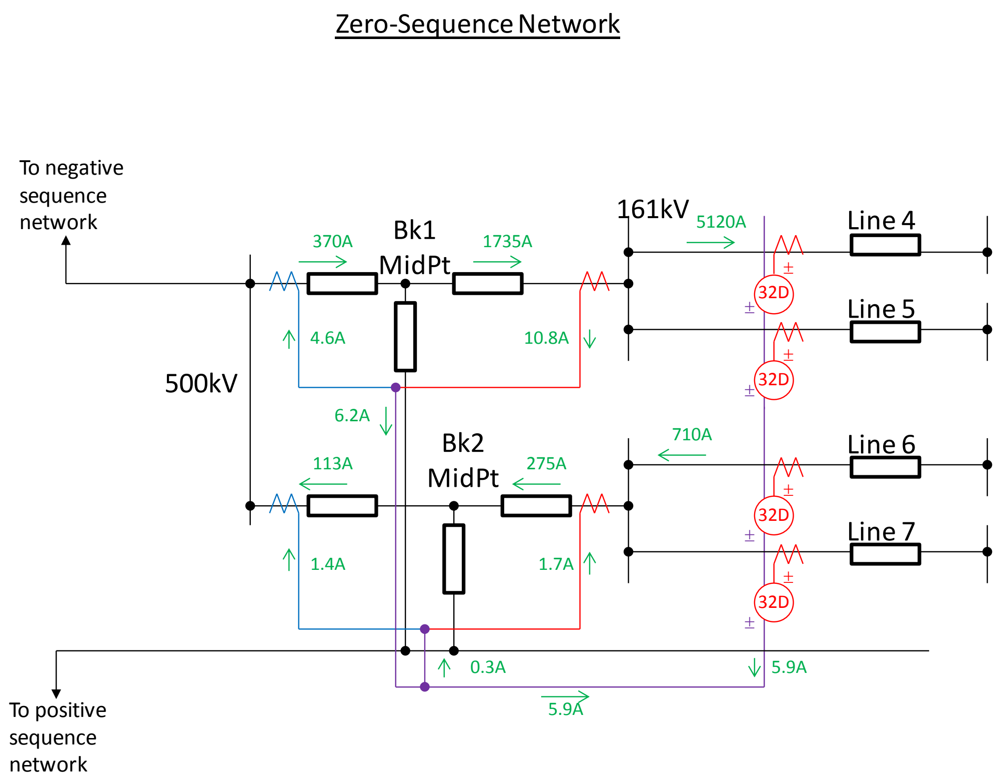


Figure 5.7.5: Line 6 polarized from Banks 1&2, correct reverse decision for fault on Line 4

This alternative method is advocated by both Blackburn and Elmore [14], [15].

6.0 Providing Recommendation on Choosing Appropriate Method

With newer microprocessor line relays, most will provide some variations of negative sequence voltage, zero sequence voltage, and zero sequence current polarizing methods. For majority of applications, the negative sequence voltage method is preferred. The matrix below will list the system configuration where one method is preferred over the others.

Configuration:	Significant Zero Sequence Mutual Coupling	Negative Sequence Voltage	Zero Sequence (Voltage, Current, or Dual)
Short and medium length lines (SIR > 0.5)	No	OK*	OK*
	Yes	OK*	NR
Long lines** (SIR ≤ 0.5)	No	SR	OK*
	Yes	SR	NR
DCB or POTT Relay at the remote terminal with zero sequence polarizing	No	NR	OK*
	Yes	NR	SR

* – OK, but study recommended
NR – Not recommended
SR – Study required
** - special compensation may be required, see section 3.6 and 3.7

7.0 Summary

Choice of polarizing method for directional ground elements is an important decision that should not be overlooked or reduced to a "cookie-cutter" approach. Each application should be carefully evaluated for adequacy. Manufacturer recommendations and/or traditional utility practices should never be used in lieu of thorough study of the particular relay in question on the protected line.

This paper has discussed the different methods available and provided application considerations and examples of misapplication. It is hoped that this material will be of use to the practicing protection engineer when determining the appropriate ground directional element.

8.0 Appendix - Examples of specific application where a particular method is inadequate

8.1 Example 1

A partial representation of three 345kV stations is shown in Figure 8.1.0. The system in this area is very strong with generation at stations A, B, and C. A C-G fault occurred on line L2. Refer to Figure 8.1.1. The relays at both ends of line L2 worked properly and tripped the line.

At Station C, line L11 has three relays protecting it: two microprocessor based relays (relays R1 and R2) and an electromechanical ground overcurrent relay (relay R3). Relay R1 misoperated for this fault because its neutral instantaneous element incorrectly operated for the fault behind the relay. The relay's instantaneous element was set to be blocked for faults sensed in the reverse direction. Current polarizing is not available at Station C, and negative sequence polarizing was not available on relay R1.

Therefore, the directionality for relay R1 was based upon voltage polarizing only, and this was calculated based upon the three phase voltage values.

Upon analysis of the oscillography, the amount of fault current on line L2 was enough to pick up the neutral instantaneous overcurrent element. Therefore, to work properly, the relay needed to sense that the fault was in the reverse direction so that this element could be blocked. It was found that the level of zero sequence voltage sensed by relay R1 never topped 0.2 volts secondary for the duration of this fault. Unfortunately, the relay required 2 volts of polarizing voltage for the directional calculation to even be performed. As a result, relay R1 misoperated.

As for the other relays on this terminal, relay R2 uses only negative sequence polarizing to determine directionality. It did not operate for the fault. Electromechanical relay R3 did not operate, either. Analysis showed that the combination of operating current and polarizing voltage was enough to provide between 1 and 2 times pickup for the relay, and this evidently was not sufficient to allow the relay to operate.

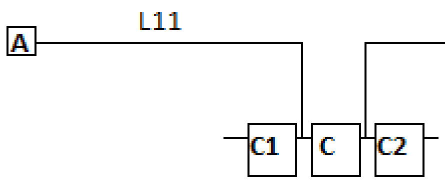


Figure 8.1.0: Example 1 Configuration

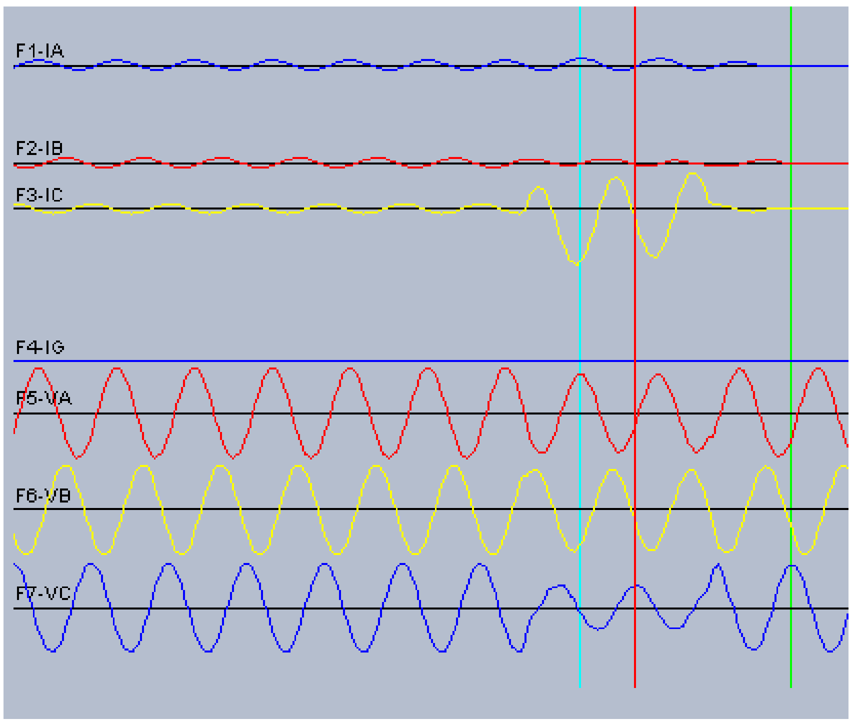


Figure 8.1.1: C-G Fault on Line L2

8.2 Example 2

In this example at Utility Y, there have been at least 2 occurrences that the Brand X relay's fallback polarizing logic resulted in false operations.

Example 2a: A 345kV line (actually 2 separate in parallel) terminated at a substation that had a 161kV line that faulted. The 161kV line was on the same right-of-way (heavily mutually coupled) for several miles before continuing on to a 161kV sub. The "a" relay (that had been set for "QV", negative sequence impedance method as the primary method, with fallback to zero sequence impedance) at the sub with the faulted line out of it declared the fault forward. The remote terminal saw the fault as forward also (which it should have) allowing the line to trip. While there was some negative sequence current, there was not enough negative sequence voltage so the heavily mutually zero sequence current allowed the directional unit declare it forward. The zero sequence fallback option has to be removed.

Example 2b: In this example of 2 138kV H frame - three terminal lines, a relay with "QV" logic is enabled. A ground fault occurred near the tapped 'mid' terminal which cleared there INST Z1G. Prior to the opening of this breaker there was significant negative sequence voltage and all relays saw the fault correctly. However, once this breaker opened there was very little negative sequence voltage and current on the paralleled unfaulted line. The mutual coupling induced significant zero sequence current which led the relay "b" to fall back to the V polarizing and it false tripped on ground overcurrent before the actual faulted line cleared.

These are 2 examples of where mutual coupling – combined with letting the relay decide the 'best logic' – which is the default logic in the relay – was a bad choice.

These two examples emphasize the importance that the protection engineers need to closely study the system to determine the need for using such logic and don't just accept the default logic in a relay.

8.3 Example 3

Using zero-sequence polarizing for directional comparison pilot scheme on line with significant mutual coupling problems

As an example of where zero-sequence polarizing is inadequate, consider the system in Figure 8.3.0.

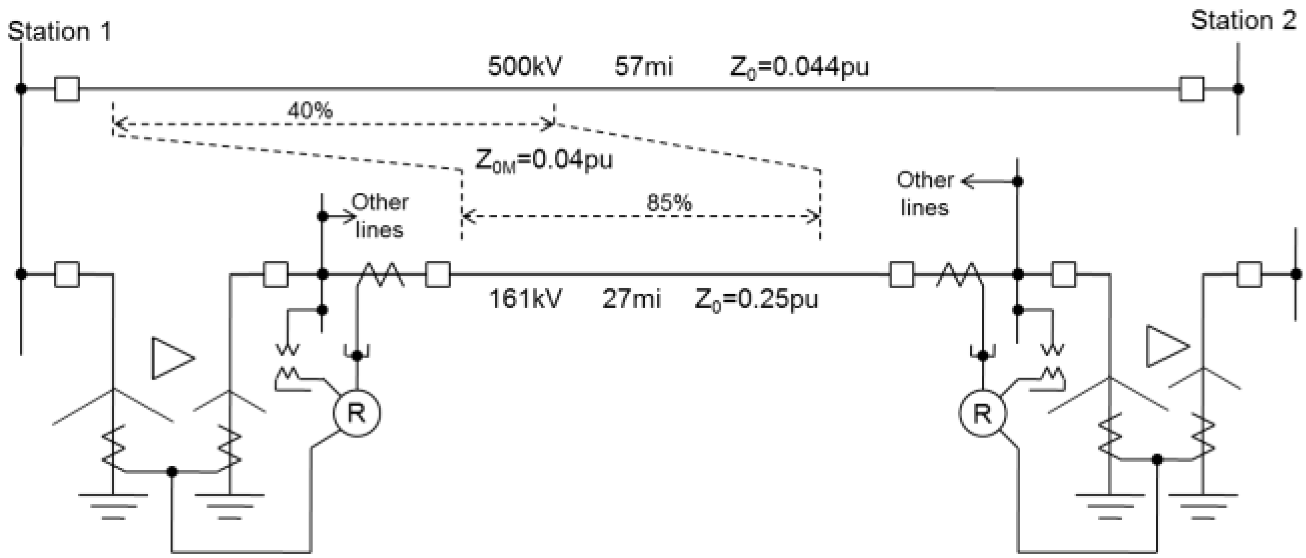


Figure 8.3.0: Sample system with mutual coupling

The 161kV line between Station 1 and Station 3 is mutually coupled with the 500kV line from Station 1 to Station 2. The mutual impedance is 0.04pu. The 161kV line is protected with a directional comparison pilot scheme having carrier ground relays with dual zero-sequence polarizing.

Neglecting the effects of mutual coupling, a ground fault on the 500kV bus at Station 1 results in zero sequence current flowing from Station 3 to Station 1 over the 161kV line. Relaying at Station 3 sees the fault as a forward fault, but relaying at Station 1 sees the fault as reverse. So a pilot scheme applied on this line would be secure. See Figure 8.3.1.

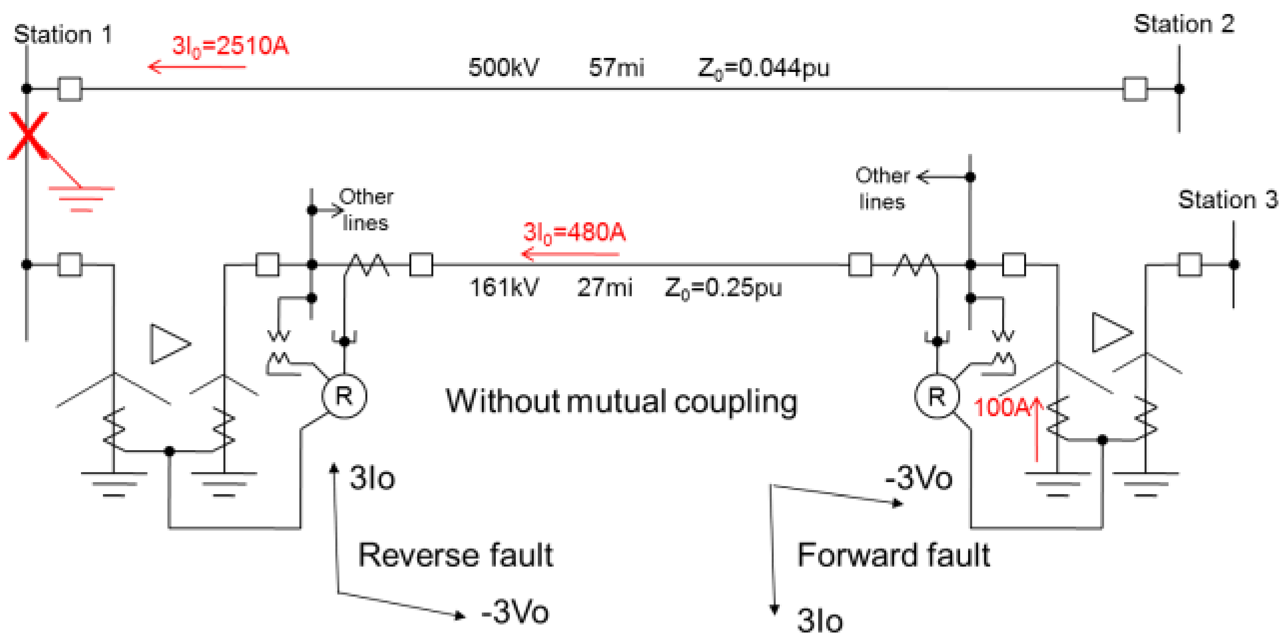


Figure 8.3.1: Fault on 500kV bus at Station 1 - Neglect mutual coupling

The partial zero-sequence network for this system is shown in Figure 8.3.2. It can be seen that polarizing currents flow away from the zero-sequence neutral node, resulting in a zero-sequence voltage rise, which results in a correct directional decision at Station 3 (same is true for Station 1).

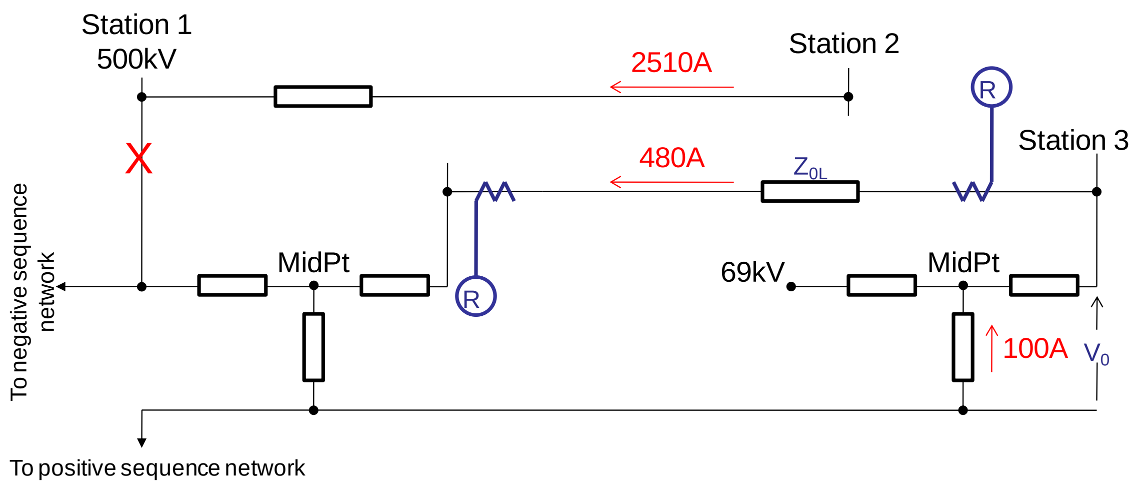


Figure 8.3.2: Partial zero-sequence network for Figure 8.3.1

However, when mutual coupling is considered, the same fault on the 500kV bus at Station 1 results in a reversal of both the zero-sequence current in the 161kV line, as well as a reversal in the zero-sequence polarizing quantities (both current and voltage) at Station 3. See Figure 8.3.3.

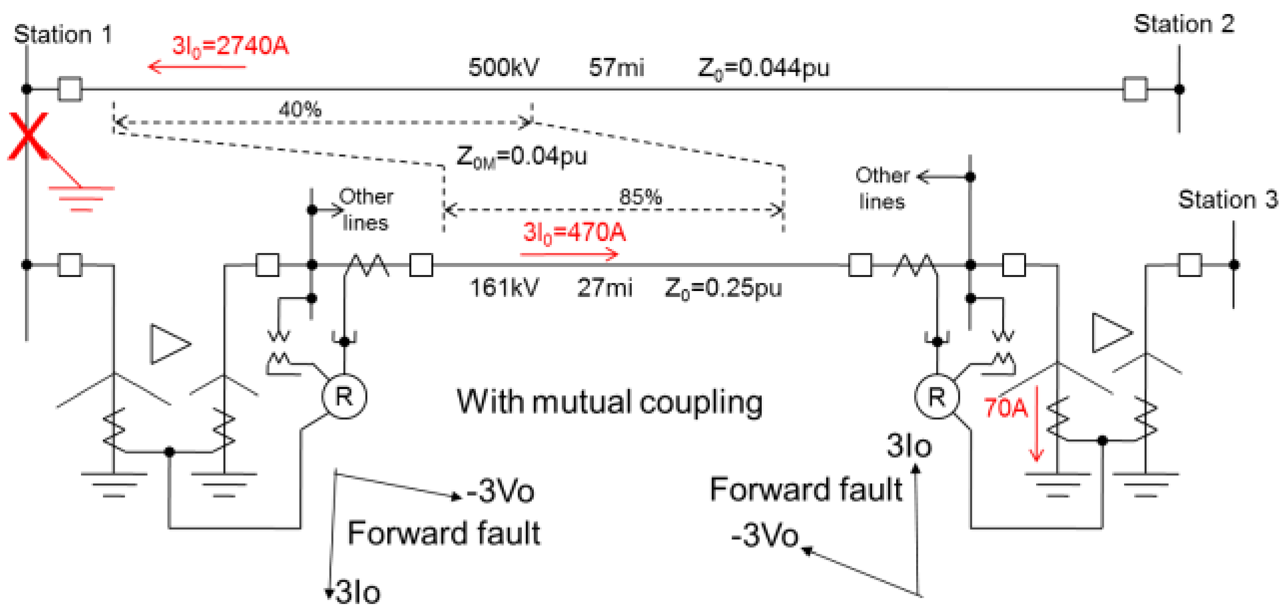


Figure 8.3.3: Fault on 500kV bus at Station 1 - Including mutual coupling

The reversal of the polarizing quantity at Station 3 results in an erroneous forward directional decision at that Station. This can be seen in the partial zero-sequence network shown in Figure 8.3.4. Current in the transformer at Station 3 flows toward the zero-sequence neutral node, resulting in a zero-sequence voltage drop, thus the reversal in both current and voltage polarizing quantities.

This error, along with the relays at Station 1 also making a forward directional decision, means that the directional comparison pilot scheme is prone to misoperate for the external fault on the 500kV bus.

Therefore, zero-sequence polarization is inadequate for this application.

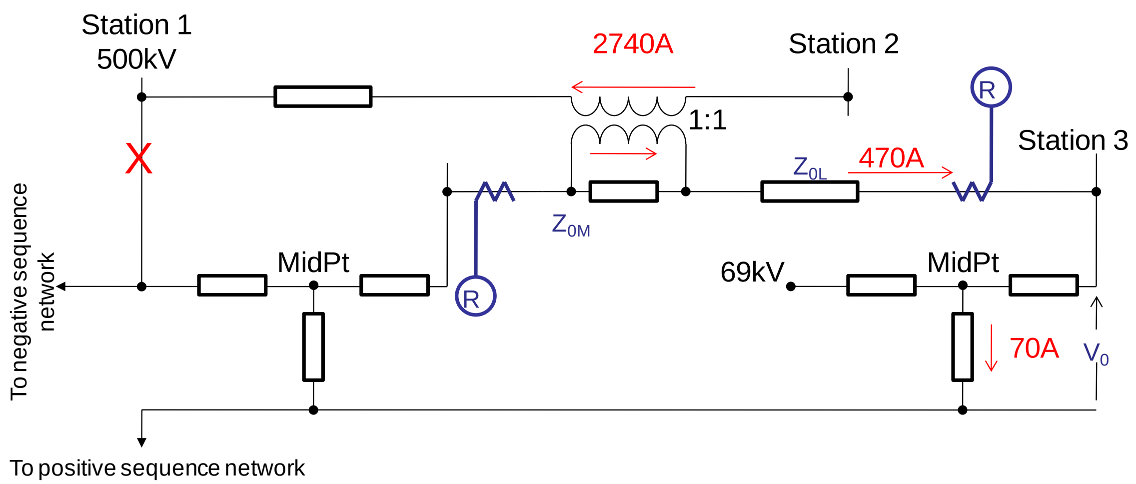


Figure 8.3.4: Partial zero-sequence network for Figure 8.3.3.

8.4 Example 4

Using negative-sequence polarizing for ground fault protection on a long (low SIR) line

As an example of where negative-sequence polarizing is inadequate, consider the system in Figure 8.4.0.

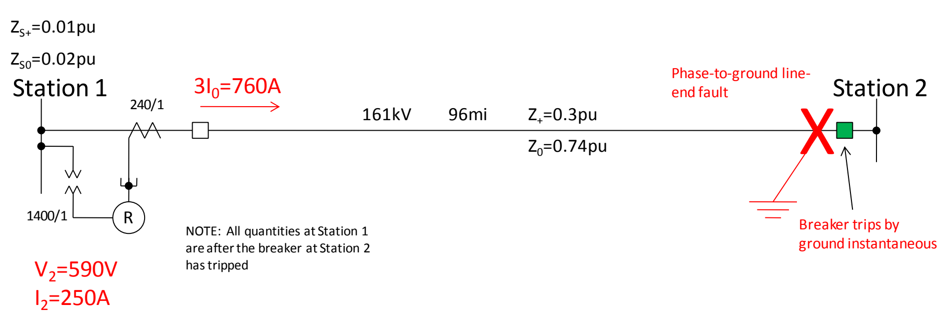


Figure 8.4.0. Sample system - line with low SIR

The line is 96 miles long, with an SIR of 0.03 [= (0.01+0.01+0.02) / (0.3 + 0.3 + 0.74)]. Negative-sequence polarizing was chosen for the directional ground element. For a phase-to-ground fault at the end of the line (after the breaker at Station 2 has opened), the negative sequence quantities at Station 1 are shown in Figure 8.4.0.

Given the instrument transformer ratios, the available negative sequence quantities at Station 1 are as follows:

V_2 = 590 / 1400 = 0.42V secondary
I_2 = 250 / 240 = 1.04A secondary

The particular relay in this example has directional element sensitivity thresholds of $V_2 \geq 1.0$V secondary and $3I_2 \geq 0.5$A secondary. The current threshold would be met ($3I_2$ = 3.12A > 0.5A), but the voltage threshold would not (V_2 = 0.42V < 1.0V), so the directional element would not operate, and the fault would have to be cleared by some other means.

For this reason, negative sequence polarizing would not be adequate for the application.

8.5 Example 5

Using negative-sequence polarizing for ground fault protection on a line with inline transformer

As an example of where negative-sequence polarizing is inadequate, consider the system in Figure 8.5.0.

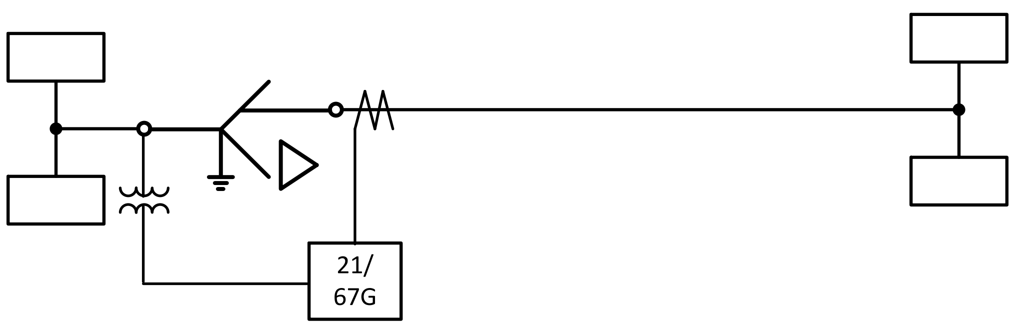


Figure 8.5.0: Sample system - line with inline transformer

The line is a common configuration with an inline power transformer that is considered as part of the line. The location of the VT can be on either side of the transformer. Phase fault protection is handled by the phase distance unit. At the terminal with the power transformer, ground fault protection is handled by a residual ground time overcurrent element, as well as Directional Comparison Blocking (DCB) residual ground overcurrent element.

For a close-in ground fault at the line side of the transformer, the fault is cleared high speed via DCB directional ground overcurrent element at both terminals. This is illustrated in Figure 8.5.1 below.

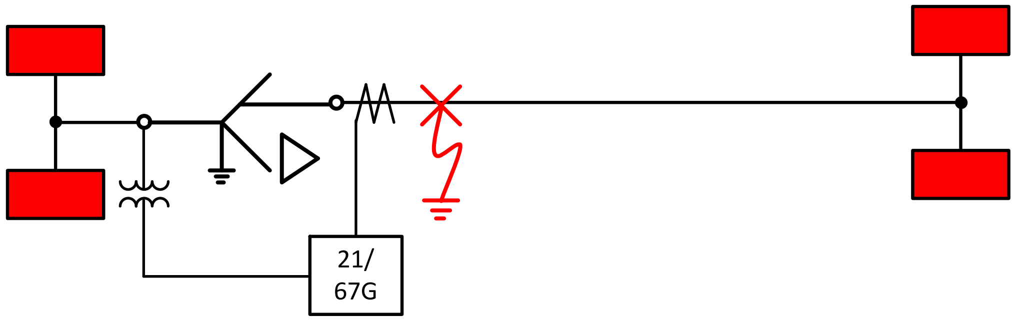


Figure 8.5.1: Close-in ground fault at the line side of the inline transformer

When reclosing is employed, a logical scenario is for the line terminal without the inline transformer to test reclose the line. If the ground fault is of a permanent nature, in the DCB scheme, the terminal should trip high speed back out after the reclose. This is illustrated in Figure 8.5.2 below.

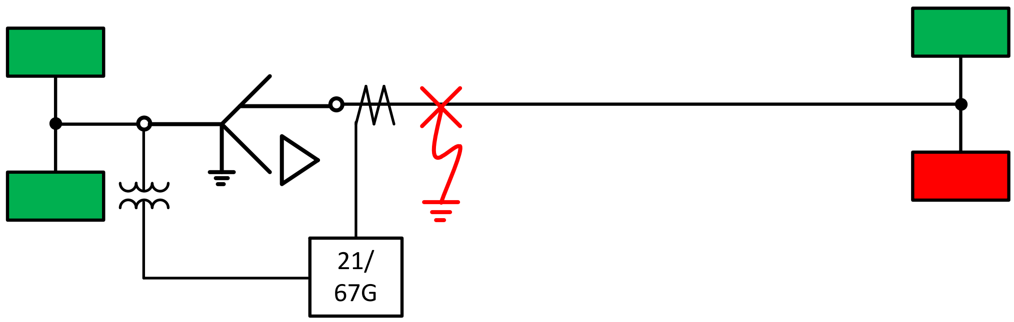


Figure 8.5.2: Close-in ground fault at the line side of the inline transformer

However, if the line DCB scheme uses non-directional start, at the inline transformer terminal, the grounded wye transformer will source zero sequence, thus initiate carrier start and block the remote terminal from high speed pilot trip. Because the breakers at the inline transformer terminal are opened, it cannot source positive sequence current and thus negative sequence current. If the directional element is set to negative sequence polarizing, directional decision cannot be made and thus cannot stop the carrier, the ground fault can only be cleared by residual ground time overcurrent.

For this reason, negative sequence polarizing would not be adequate for the application.

9.0 References and technical documents

Publications Pertaining to Ground Directional Element Polarizing methods:

[1] "Polarization Fundamentals", by Walter Elmore and Elmo Price, 27th Annual Western Protective Relay Conference, Spokane, WA, Oct. 24-26, 2000,

[2] "Polarizing Sources for Directional Ground Relays" by Joe Andrichak and Subhash C. Patel, General Electric Application Notes and Paper, Reference # GER-3182

[3] “Comparing Ground Directional Element Performance Using Field Data” by Karl Zimmerman and Joe Mooney, Schweitzer Engineering Laboratories, Inc., Technical paper date code 19930401
[4] “Ground Fault Relay Protection of Transmission Lines” by J.L. Blackburn, AIEE Transaction Part III, Vol 71, pg 685-691, Aug 1952
[5] “Ground Relay Polarization” by J.L. Blackburn, AIEE Transaction Part III, Vol 71, pg 1088-1093, Dec 1952
[6] “The Art and Science of Protective Relaying”, Chapter 13 Line Protection with Overcurrent Relays, Section: Polarizing the Directional Units of Ground Relays, Section: Negative-phase-sequence directional Units for Ground-fault Relaying, by C. Russell Mason,
[7] “Effect of Load Flow on Relay Performance”, General Electric Application Notes and Paper, Reference # GER-3743
[8] “Advanced Application Guidelines for Ground Fault Protection”, by Joe Mooney, 28th Annual Western Protective Relay Conference, Spokane, WA, Oct. 23-25, 2001
[9] "Arrows in One-Line Displays in the Computer-Aided Protection Engineering System (CAPE)," Prepared for CAPE Users' Group, Electrocon International, Inc., Ann Arbor MI; June 20-21, 2006
[10] "Setting SEL-321 Relays," Electrocon International, Inc., Ann Arbor MI; November 11, 2008
[11] "Generic Distance Relay UTP-100#WPSC1," Electrocon International, Inc., Ann Arbor MI; August 24, 1998
[12] "Automatic Relay Setting", by Donald M. MacGregor, A. T. ("Tony") Giuliante, and Russell W. Patterson, presented at 56th Annual Georgia Tech Protective Relaying Conference, Atlanta, Georgia; May 1-3, 2002, and at 55th Annual Conference for Protective Relay Engineers, Texas A&M University, College Station, Texas; April 9-11, 2002
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[14] “Protective Relaying – Principles and Applications”, 3rd edition, J.L. Blackburn, Chapter 12, Section 12.24, pp 460-461
[15] “ABB Protective Relaying Theory and Applications”, 2nd edition, Revised and Expanded, W. A. Elmore, Chapter 12, Section 3. 4, pp 243-244
[16] "CCVT Failure due to Improper Design of Auxiliary Voltage Transformers", Davarpanah M, et all, IEEE Transactions on Power Delivery, Jan. 2012, pp. 391-400