Back to Table of Contents

Negative-Sequence Overcurrent – Distribution Coordination Examples

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Abstract

Negative-sequence overcurrents are now widely available as an extra "free" feature in many microprocessor-based relays. Use of the negative-sequence function can provide more sensitivity and faster clearing times for unbalanced (non three-phase) system faults. This allows the system protection engineer to better protect equipment and people. Unfortunately, how best to use the negative-sequence function is sometimes difficult to grasp and so the feature is often not utilized. Guidelines for setting the negative-sequence element are listed. Several examples are provided to show, and further explain, how to set these elements on radial distribution systems.

Introduction

Use of symmetrical components allows faults on the power system to be analyzed utilizing positive, negative and zero-sequence quantities. Historically, relays were applied on the distribution system that monitored phase current and the ground current (zero-sequence current). Unfortunately, no current transformer connection is available to directly provide negative-sequence. To develop the negative-sequence quantity inside an electro-mechanical relay required an expensive relay and consequently negative-sequence relaying on distribution was rarely, if ever, used. The ability of the microprocessor relay to calculate the negative-sequence overcurrent value allows this basic quantity to be available for improving the protection on the electrical system.

Benefits of using Negative-Sequence Overcurrent

For three-phase totally balanced load, there is no negative-sequence current flow. Just as there is no zero-sequence flow. However, differences in phase loading (e.g. different single-phase load on each phase) will result in some negative- (and zero-) sequence flow. Normally, the negative-sequence and zero-sequence currents are relatively low and are mostly unaffected by increases in three-phase load current. A negative-sequence element responds to single-phase switching, similar to what happens with ground relays.

Negative-sequence overcurrents are calculated in the relay strictly from the three phase currents. The relay does not need voltage inputs as a distance relay would require.

As a result of not responding to balanced three-phase load current, the negative-sequence element can often be set significantly more sensitive than a traditional phase element. This increased sensitivity makes backup of downstream interrupting devices easier to attain.

Faster clearing times are possible too. These faster clearing times reduce the duration of the voltage sag seen by other customers fed from non-faulted feeders in the affected area. Faster clearing times also help limit damage at the fault location and improve the odds that a reclose attempt will be able to successfully re-energize the phase.

Special Concerns/Issues

When selecting the negative-sequence pickup setting, operating conditions that result in unbalanced current need to be considered to ensure that the setting is not too sensitive. Unbalanced currents occur due to single-phase loads, single-phase switching, blown tap fuses, blown capacitor bank fuses, etc. This is similar to considerations for making the ground overcurrent element pickup setting.

Some relays have settings based on $3I_2$, versus others that use I_2. Throughout this paper, the values shown are based on setting a relay that utilizes $3I_2$. For a relay using I_2, merely divide these values by three.

Negative-Sequence Current Comparison

Each type of fault can be broken down into sequence components. Of interest is the ratio of the magnitudes of the negative-sequence current ($3I_2$) to phase current (I_P) and of the zero-sequence current ($3I_0$) to the phase current (I_P) on the primary system. These ratios are used when setting relay elements that respond to these sequence quantities.

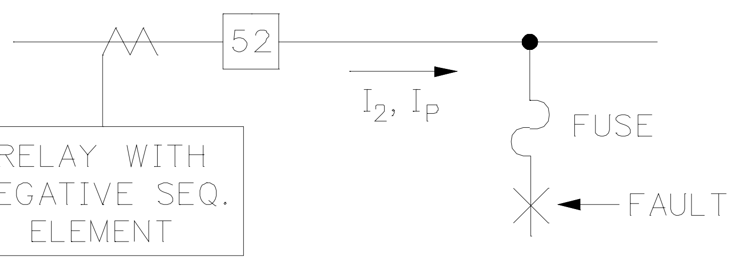

Figure 1 Fault on Radial Distribution System

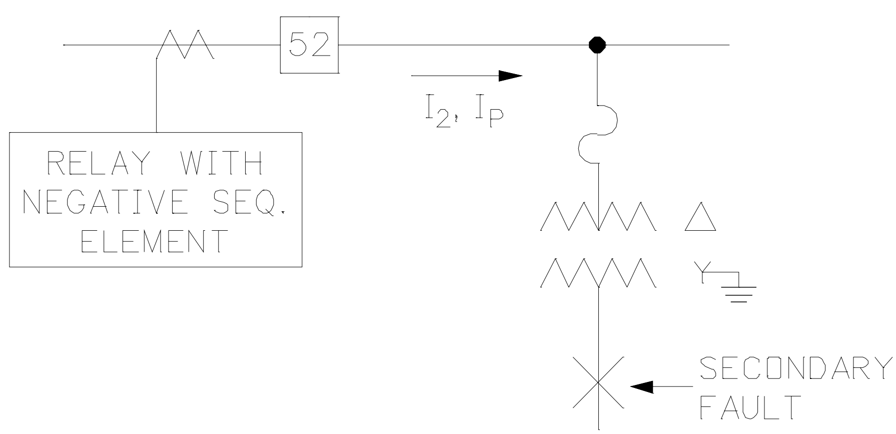

Figure 2 Fault on Secondary of Delta-Wye Transformer

Table 1 Faults on a Radial Distribution System

Fault Type	Sequence Current / Phase Current: Negative $|3I_2/I_P|$	Zero $|3I_0/I_P|$
Three-Phase	0	0
Double-Phase-to-Ground	less than or equal to $\sqrt{3}$	less than or equal to $\sqrt{3}$
Phase-to-Phase	$\sqrt{3}$	0
Single-Phase-to-Ground	1	1
Phase-to-Phase on secondary of delta/wye transformer bank	1.5	0
Single-Phase-to-Ground on secondary of delta/wye transformer bank	$\sqrt{3}$	0

Negative-Sequence Overcurrent Pickup Setting Limits

Table 1 shows that the ratio of $|3I_2/I_P|$ will never exceed $\sqrt{3}$. Therefore, within the same relay, if a negative-sequence element pickup is set equal to or greater than $\sqrt{3}$ times the phase element pickup, it does not provide any additional sensitivity for phase-to-phase faults.

For a single-phase-to-ground fault, Table 1 shows that the ratios of $|3I_2/I_P|$ and $|3I_0/I_P|$ both equal "1." This means that for a single-phase-to-ground fault $|3I_2/3I_0|$ also equals "1". Therefore, within the same relay, a negative-sequence element pickup must be set equal to or greater than the ground element pickup to avoid being more sensitive than the ground element for a single-phase-to-ground fault.

If fuses on single-phase taps are the only protective devices beyond a negative-sequence overcurrent element, then the negative-sequence overcurrent element pickup is set somewhat higher than the fuse's maximum clearing curve for coordination. Only single-phase-to-ground faults are possible on single-phase taps and as discussed previously, $|3I_2/3I_0| = 1$ for single-phase-to-ground faults. Most likely, a ground overcurrent element at this same relay position is coordinated similarly with the fuses on these single-phase taps.

But, usually there are not just fused single-phase taps beyond a negative-sequence overcurrent element. There are multi-phase taps protected by fuses, line reclosers, or other protection devices, where not only single-phase-to-ground faults occur, but multi-phase faults as well. In this situation, if the ground relay element is coordinated with all downstream phase devices, then a negative-sequence element pickup of $\sqrt{3}$ times the ground element pickup (along with the same curve and time lever as the ground element) provides coordination with the downstream phase devices for multi-phase faults.

A Simple Method to Determine Negative-Sequence Overcurrent Settings

1. Begin with the farthest downstream negative-sequence overcurrent element (e.g. the line recloser).

2. Determine the phase overcurrent device (relay, line recloser, fuse) downstream from the negative-sequence overcurrent element that is the greatest coordination concern (usually the longest clearing time).

3. Derive the farthest downstream negative-sequence overcurrent element settings using an "equivalent" phase overcurrent element. Disregarding load, coordinate this "equivalent" phase overcurrent element with the downstream phase overcurrent device of concern. Select the pickup, time lever, and curve type for the "equivalent" phase overcurrent element, again disregarding load. In cases where the ground relay element is coordinated with all downstream phase devices, this "equivalent" phase overcurrent can be set to match the ground overcurrent curve.

4. Once the settings are determined for the "equivalent" phase overcurrent element, multiply the pickup by $\sqrt{3}$ to convert to a negative-sequence ($3I_2$) overcurrent pickup setting (from Table 1, $|3I_2/I_P|$ never exceeds $\sqrt{3}$). The time lever and curve type settings are used directly for the negative-sequence overcurrent element settings, with no conversion required.

5. Coordinate the next upstream negative-sequence overcurrent element with the farthest downstream negative-sequence overcurrent element (much like coordinating ground overcurrent elements – providing some margin, allowing for unbalance, and disregarding load). Also, coordinate this next upstream negative-sequence overcurrent element with any phase overcurrent devices on this line section (between the farthest downstream negative-sequence overcurrent element and this next upstream negative-sequence overcurrent element).

6. This process repeats for coordinating each successive, upstream negative-sequence overcurrent element.

Coordination Examples – General

The purpose of the examples is to show the usage of the simple method of setting the negative-sequence element. The intent is not to infer that the settings in the examples are the ideal settings. Different margins to accommodate load current, unbalance current, or coordination time intervals may be desired. These margins vary by a utility engineer's preference. For the sake of simplicity, CO-9 curves are used throughout the examples.

Coordination Examples

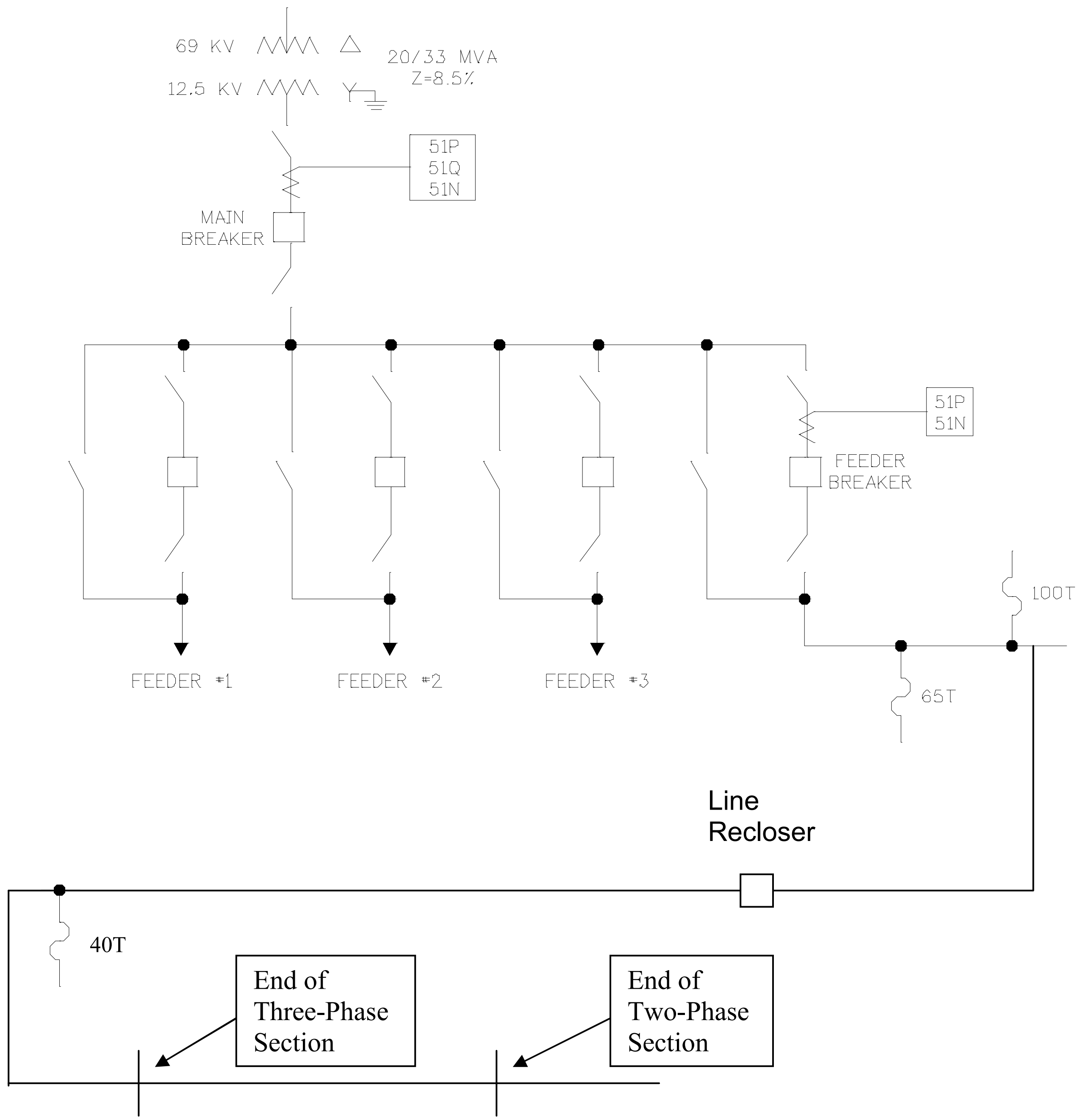

Figure 3 12.5 kV Distribution System
(Used with Examples 1, 2, & 3)

Coordination Examples

Example #1: Line recloser with a tap fuse

Per Figure 3, a three-phase line recloser is located a mile from the substation and is protecting the end of the 12.5 kV feeder.
I_R = The maximum load beyond the line recloser is 4 Megawatts + 1.5 Megavar.

I_{MAX} = The fault current directly in front of the line recloser is 2000 Amps (three-phase), 1200 Amps (phase-to-ground).

$I_{MIN\ 3\text{-}Ph}$= The three-phase fault current at the end of the three-phase section is 1000 Amps.

$I_{MIN\ Ph\text{-}Ph}$= The phase-to-phase fault current at the end of the farthest two-phase section is 600 Amps.

$I_{MIN\ Ph\text{-}G}$= The phase-to-ground fault current at the end of the farthest single-phase tap is 300 Amps.

The largest fuse beyond the line recloser is a 40T.

Determine settings for the line recloser. Compare the sensitivity improvement for phase-to-phase faults by using a negative-sequence overcurrent element. Show the percentage improvement in clearing time for a line-end phase-to-phase fault.

The maximum load current at the line recloser is:
4 Megawatt + 1.5 Megavar = 4.272 MVA
4.272 MVA / (12.5 kV x √3) = 197.3 Amps

To accommodate maximum load current try using a phase pickup that is 135% of maximum expected load. Try 135% x 197.3 = 266.4 Amps. The time-overcurrent curve must coordinate with at least a 40T fuse. Use a phase pickup of 280 Amps, CO-9 curve, time lever = 2.

Ground pickup is independent of downstream balanced load. It must be set above the coordination curve for the 40T fuse. The maximum clearing current of the 40T fuse is approximately 100 Amps for 10 minutes. Use 140 Amps for the ground pickup, CO-9 curve, time lever = 3.

The negative-sequence pickup is independent of downstream balanced load. It must be set above the coordination curve for the 40T fuse. Approximately, the maximum clearing current of the 40T fuse (at 10 minutes) corresponds to a $3I_2$ current of 100 Amps for ground faults and 100 Amps times √3 for a phase-to-phase fault.

To ensure coordination of the negative-sequence overcurrent, use an "equivalent" phase pickup of 140 Amps. This results in a negative-sequence pickup of 242 Amps (140 Amps times √3). Use CO-9 curve time lever = 3.

The sensitivity improvement for phase-to-phase faults by applying a negative-sequence overcurrent element is from a phase sensitivity of 280 Amps to an "equivalent" phase sensitivity of 140 Amps. For a 600 Amp phase-to-phase fault at the end of the farthest two-phase section, the phase element would operate in 2.35 seconds and the negative-sequence element in 0.89 second. This corresponds to an improvement in clearing time of 60+%.

Example #2: Substation feeder breaker with a line recloser

Per Figure 3, the largest fuse beyond the feeder breaker is a 100T. The fault current directly in front of the feeder breaker is 5000 Amps (three-phase), 5200 Amps (Phase-to-Ground). The maximum load current on the 12.5 kV feeder breaker is 600 Amps.

A three-phase line recloser (from the previous example) is located one mile downstream. The line recloser (per the previous example) has a phase pickup of 280 Amps, a negative-sequence pickup ($3I_2$) of 242 Amps, and a ground pickup of 140 Amps.

Determine the relay settings for the breaker. Without the use of negative-sequence settings, is it possible for the feeder breaker to provide backup for 600 Amp phase-to-phase faults at the end of the two-phase section fed by the line recloser?

To accommodate maximum load current try using a pickup that is 135% of maximum expected load. Try 135% x 600 = 810 Amps. Use a phase pickup of 800 Amps, CO-9 curve, time lever = 1.25.

Ground pickup must be set above the coordination curves for the 100T fuse and for the line recloser. The maximum clearing current of the 100T Fuse for 10 minutes is approximately 250 Amps and is higher than the 140 Amp line recloser curve. Use 400 Amps for the ground pickup, CO-9 curve, time lever = 2.5.

For setting the negative-sequence pickup, need to consider both the maximum downstream fuse (100T) and the 242 Amp negative-sequence pickup on the downstream line recloser. To provide coordination with the maximum clearing current of the 100T Fuse, try 400 Amps times √3 equals 693 Amps for the negative-sequence pickup. This is above the 242 Amp negative-sequence pickup of the downstream line recloser. Use a negative-sequence pickup of 693 Amps, CO-9 curve, time lever = 2.5.

The 800 Amp phase pickup is above the 600 Amp phase-to-phase fault current at the end of the two-phase line section beyond the line recloser. Therefore, the phase overcurrent element does not operate (provide backup) for a phase-to-phase fault at this location. Fortunately, the negative-sequence pickup of 693 Amps (with an "equivalent" phase pickup of 400 Amps; 693 Amps divided by √3) will easily see this fault and provide backup coverage.

Example #3: Substation main breaker with a feeder breaker

Per Figure 3, the main breaker is on the low-side of a 20/33 MVA 69/12.5 kV transformer. It serves a 12.5 kV bus with four feeder breakers with settings per the previous example. The feeder breakers each have bypass switches to allow for maintenance of the feeder breakers while keeping the feeder energized.

Determine relay settings for the main breaker. Due to the use of the bypass switches on the feeders breakers it is desirable, to the extent possible, for the main to backup the next device beyond the feeder breaker. With the use of negative-sequence settings, is it possible for the main breaker to provide complete backup (per the previous example) for the 600 Amp phase-to-phase fault at the end of the two-phase line section beyond the line recloser?

The maximum load current at the main breaker is:
33 MVA / (12.5 kV x √3) = 1524 Amps

To accommodate maximum load current try using a pickup that is 135% of maximum expected load.
Try 135% x 1524 = 2057 Amps. Use a phase pickup of 2000 Amps, CO-9 curve, time lever = 1.5.
Ground pickup must be set above the ground pickup on the feeders. Use 480 Amps for the ground pickup, CO-9 curve, time lever = 4.

For the negative-sequence pickup, set slightly above the 700 Amp negative-sequence pickup on the downstream feeder breakers. Use a negative-sequence pickup of 831 Amps, CO-9 curve, time lever = 4.

The 831 Amp negative-sequence pickup has an "equivalent" phase pickup of 480 Amps (831 Amps divided by √3). Since this is less than the 600 Amp phase-to-phase fault value at the end of the two-phase line section beyond the downstream line recloser, the main breaker is able to backup the line recloser for all phase-to-phase faults on the system. As the feeder breaker is rarely bypassed, the use of the negative-sequence element in this example allows the main breaker to provide "double contingency" backup for failure of both the feeder breaker and the line recloser.

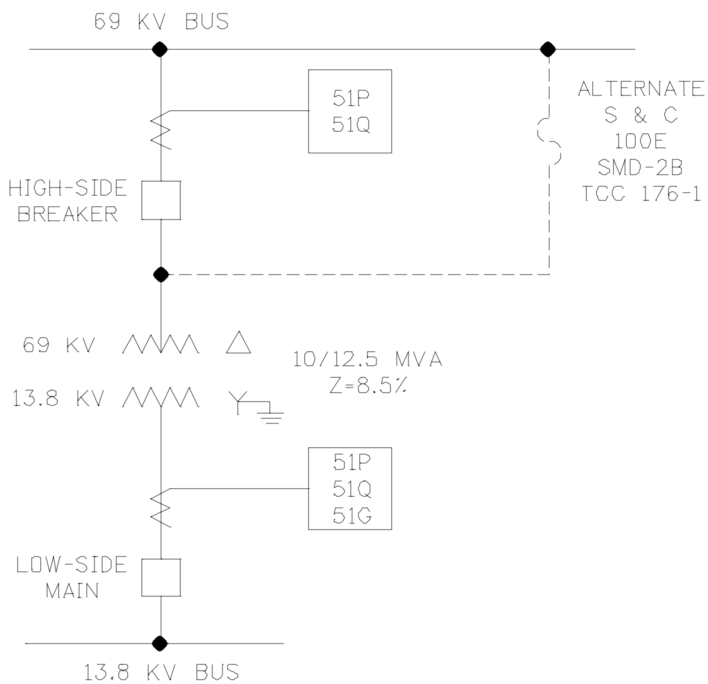

Figure 4 Substation transformer with either high-side breaker or fuses.

Example #4: Substation transformer high-side fuses / relays with main breaker

Per figure 4, a 10/12.5 MVA 69/13.8 kV transformer installation is being planned. The transformer has a delta winding on the 69 kV side and a grounded-wye winding on the 13.8 kV side. The impedance is 8.5% on the transformer's 10 MVA base rating. The positive-sequence source impedance on the 69 kV side is 1% on 10 MVA. The high-side fuse (when used) will be an S&C 100E, SMD-2B, TCC 176-1. The low-side main breaker has settings of:
Phase pickup = 800 Amps, CO-9 curve, time lever = 3.5.
Negative-Sequence pickup = 624 Amps, CO-9 curve, time lever = 5.5.
Ground pickup = 360 Amps, CO-9 curve, time lever = 6.

Show the difference in clearing times for backing up the low-side breaker that can be provided by utilizing a high-side 69 kV breaker with an overcurrent relay (complete with negative-sequence settings) to protect the transformer versus traditional fuses. Also, check coordination of the low-side and high-side overcurrent elements.

For the high-side breaker, use the following settings:
Phase pickup = 250 Amps, CO-9 curve, time lever = 3.2 (selected to match the 100E S&C fuse).
Negative-Sequence pickup = 200 Amps, CO-9 curve, time lever = 6.5.

Each type of unbalanced fault on the low-side of a delta-wye transformer bank results in a different high-side current magnitude. These different current magnitudes need to be compared to see if any high-side overcurrent elements miscoordinate with the low-side overcurrent elements. Following Table 2 (for phase-to-ground faults) and Table 3 (for phase-to-phase faults) are used to make these comparisons.

I_{P-H} maximum phase current, high-side of delta-wye transformer bank

I_{P-L} maximum phase current, low-side of delta-wye transformer bank

$3I_{2-H}$ negative-sequence current, high-side of delta-wye transformer bank

$3I_{2-L}$ negative-sequence current, low-side of delta-wye transformer bank

V_H nominal phase-to-phase voltage, high-side of delta-wye transformer bank = 69 kV

V_L nominal phase-to-phase voltage, low-side of delta-wye transformer bank = 13.8 kV

$V_L/V_H = 13.8/69 = 1/5 = 0.2$

Table 2 Transforming Current Values for a Phase-to-Ground Fault on the Low-Side of a Delta-Wye Transformer Bank

low-side current magnitude	x (delta-wye transformer bank factor for given fault and currents)	= equivalent high-side current magnitude
$3I_{2-L}$	x (V_L/V_H)	$3I_{2-H}$
I_{P-L}	x (V_L/V_H)	$3I_{2-H}$
$3I_{2-L}$	x $(V_L/(\sqrt{3}\ V_H))$	I_{P-H}
I_{P-L}	x $(V_L/(\sqrt{3}\ V_H))$	I_{P-H}

Table 3 Transforming Current Values for a Phase-to-Phase Fault on the Low-Side of a Delta-Wye Transformer Bank

low-side current magnitude	x (delta-wye transformer bank factor for given fault and currents)	= equivalent high-side current magnitude
$3I_{2-L}$	x (V_L/V_H)	$3I_{2-H}$
I_{P-L}	x $((\sqrt{3}\ V_L)/V_H)$	$3I_{2-H}$
$3I_{2-L}$	x $((2\ V_L)/(3\ V_H))$	I_{P-H}
I_{P-L}	x $((2\ V_L)/(\sqrt{3}\ V_H))$	I_{P-H}

Table 4 and Table 5 mimic Table 2 and Table 3, respectively, with low-side overcurrent element pickups entered and then transformed to equivalent high-side pickups. These equivalent high-side pickups are then compared to the corresponding actual high-side overcurrent element pickups to see if any high-side overcurrent elements miscoordinate with the low-side overcurrent elements.

Table 4 Comparing Overcurrent Element Pickup Values for a Phase-to-Ground Fault on the Low-Side of a Delta-Wye Transformer Bank

low-side current pickup	x (delta-wye transformer bank factor for given fault and currents)	= equivalent high-side current pickup	compare to actual high-side current pickups
624 A ($3I_{2\text{-}L}$)	x (V_L/V_H)	124.8 A ($3I_{2\text{-}H}$)	< 200 A ($3I_{2\text{-}H}$)
800 A ($I_{P\text{-}L}$)	x (V_L/V_H)	160 A ($3I_{2\text{-}H}$)	< 200 A ($3I_{2\text{-}H}$)
624 A ($3I_{2\text{-}L}$)	x ($V_L/(\sqrt{3}\ V_H)$)	72.1 A ($I_{P\text{-}H}$)	< 250 A ($I_{P\text{-}H}$)
800 A ($I_{P\text{-}L}$)	x ($V_L/(\sqrt{3}\ V_H)$)	92.4 A ($I_{P\text{-}H}$)	< 250 A ($I_{P\text{-}H}$)

Table 5 Comparing Overcurrent Element Pickup Values for a Phase-to-Phase Fault on the Low-Side of a Delta-Wye Transformer Bank

low-side current pickup	x (delta-wye transformer bank factor for given fault and currents)	= equivalent high-side current pickup	compare to actual high-side current pickups
624 A ($3I_{2\text{-}L}$)	x (V_L/V_H)	124.8 A ($3I_{2\text{-}H}$)	< 200 A ($3I_{2\text{-}H}$)
800 A ($I_{P\text{-}L}$)	x ($(\sqrt{3}\ V_L)/V_H$)	277.1 A ($3I_{2\text{-}H}$)	> 200 A ($3I_{2\text{-}H}$)
624 A ($3I_{2\text{-}L}$)	x ($(2V_L)/(3\ V_H)$)	83.2 A ($I_{P\text{-}H}$)	< 250 A ($I_{P\text{-}H}$)
800 A ($I_{P\text{-}L}$)	x ($(2\ V_L)/(\sqrt{3}\ V_H)$)	184.8 A ($I_{P\text{-}H}$)	< 250 A ($I_{P\text{-}H}$)

Looking at the comparisons in the two right-hand columns of Table 4 and Table 5, all the high-side current pickups are set less sensitive than the low-side current pickups for proper coordination (assuming curve type and time lever settings are also adequate), except for the second row of Table 5 (277.1 A > 200 A). This exception is for a phase-to-phase fault on the low-side of a delta-wye transformer bank and the apparent miscoordination between a low-side phase overcurrent element and a high-side negative-sequence overcurrent element. The low-side phase overcurrent element pickup [800 A ($I_{P\text{-}L}$)] is transformed to an equivalent high-side negative-sequence current pickup [277.1 A ($3I_{2\text{-}H}$)] and an apparent miscoordination appears [277.1 A ($3I_{2\text{-}H}$) > 200 A ($3I_{2\text{-}H}$)].

But, if the low-side negative-sequence overcurrent element is enabled and is set more sensitively than the high-side negative-sequence overcurrent element for a phase-to-phase fault on the low-side of a delta-wye transformer bank, then this apparent miscoordination between the low-side phase overcurrent element and the high-side negative-sequence overcurrent element can be disregarded. The first row of Table 5 (124.8 A < 200 A) proves that such is the case and that this apparent miscoordination in the second row of Table 5 can be disregarded (again, if the low-side negative-sequence overcurrent element is enabled).

Table 6 Operating Times for Bus Faults beyond the Low-Side Main Breaker

Device	------------ Operating Times (seconds) ------------		
	Three-Phase	Phase-to-Phase	Phase-to-Ground
High-Side Fuse	1.19	1.19	3.61
High-Side breaker / relay	1.19	1.19	1.85
Low-side main breaker	0.72	0.74	0.71

Per Table 6, slower clearing times for the high-side fuse occurs for a low-side single-phase-to-ground fault in comparison to a three-phase fault due to the effect of the delta-wye transformation. In this example, the high-side breaker with negative-sequence relaying can provide backup clearing of a low-side phase-to-ground bus fault with almost a 50% reduction in operating time.

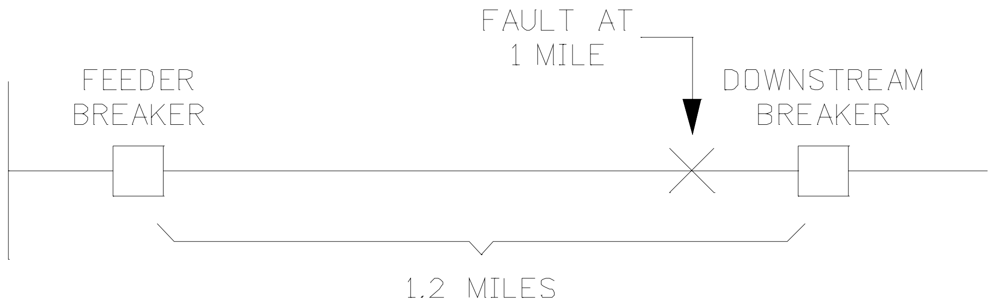

Figure 5 New Feeder – One-Line

Example #5:

A new feeder per Figure 5 is being installed and the first downstream protective device is located 1.2 miles downstream. To help avoid damage to the wire on the feeder, a phase instantaneous on the feeder breaker is set for 3000 Amps. This corresponds to the three-phase fault current one mile downstream from the breaker.

Determine the negative-sequence setting that provides phase-to-phase coverage for the first one mile of line thereby matching the coverage of the phase instantaneous for three-phase faults.

V = nominal phase-to-phase voltage

Z = system impedance

Three-phase fault = $(V/\sqrt{3})/Z$

Phase-to-phase fault = $V/(2\ Z)$

Negative-sequence overcurrent element pickup ($3I_2$ base) = $(\sqrt{3}\ V)/(2\ Z)$

Ratio of negative-sequence overcurrent element pickup (set to cover phase-to-phase faults) to phase instantaneous overcurrent element pickup (set to cover three-phase faults):

$[(\sqrt{3}\ V)/(2\ Z)]/[(V/\sqrt{3})/Z] = 3/2 = 1.5$

Thus, the phase instantaneous overcurrent element pickup can be multiplied by 1.5 to get the negative-sequence overcurrent element pickup.

In this example, the negative-sequence setting is 4500 Amps (3000 Amps x 1.5). Please note that negative-sequence current can transiently appear when a breaker is closed and balanced load current suddenly appears. To avoid tripping for this transient condition, use a negative-sequence definite-time with at least a 1.5 cycle delay.

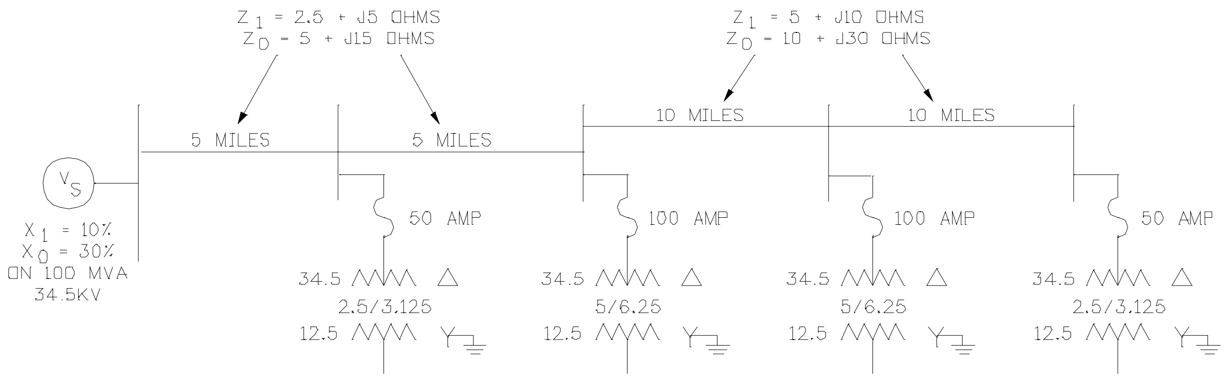

Figure 6 34.5 kV Radial System

Example #6: Sub-transmission radial feeder with substation transformer high-side fuses /relays

Per Figure 6, a 30 mile long 34.5 kV radial line is serving two 5/6.25 MVA and two 2.5/3.125 MVA distribution substations. The 34.5 kV transformer fuses on the 5/6.25 MVA transformers are 100 Amp. The transformers have delta winding on their 34.5 kV side to a grounded-wye winding on their 12.5 kV side. The impedances are 7.5% on the transformer's base rating. The source and phase impedances are noted in figure 6.

What issues need to be considered when setting the negative-sequence setting on the sub-transmission feeder? What advantages does negative-sequence provide in this application?

The maximum load current on the sub-transmission feeder breaker is:
3.125 + 6.25 + 6.25 + 3.125 MVA = 18.75 MVA
18.75 MVA / (34.5 kV x √3) = 314 Amps

To accommodate maximum load current try using a pickup that is 135% of maximum expected load. Try 135% x 314 = 424 Amps. The phase time-overcurrent curve must coordinate with at least a 100 Amp fuse. Use a pickup of 440 Amps, CO-9 curve, time lever = 1.

As the transformers have delta high-side winding configurations, there will be no ground current flow through the transformers. A sensitive ground pickup can be used to protect for frequent line ground faults. This ground relay may beat the 34.5 kV transformer fuses for a ground fault in the delta winding of the transformer, however internal transformer bank faults rarely occur. Use 40 Amps for the ground pickup, CO-9 curve, time lever = 1.

When setting the negative-sequence element, coordination with the downstream transformer fuses must be considered. The maximum clearing current of the 100 Amp fuse is approximately 200 Amps. To provide coordination use an "equivalent" phase pickup of 250 Amps for the negative-sequence element. This corresponds to a $3I_2$ setting of 250 Amps x √3 = 433 Amps. Use 440 Amps for the negative-sequence pickup, CO-9 curve, time lever = 2.

In this situation, the "equivalent phase" 254 Amp (440 Amps divided by √3) pickup of the negative-sequence element is significantly above the 40 Amp pickup of the ground element. However the "equivalent phase" pickup of 254 Amp still provides more sensitivity than the 440 Amp pickup of the phase element and so operating improvement will occur via use of the negative-sequence element.

Advantages provided are more sensitive and faster clearing for phase-to-phase 34.5 kV faults as well as backup for phase-to-ground faults on the low-side of the distribution substation transformers.

A 12.5 kV phase-to-ground fault on the 5/6.25 MVA transformer closest to the source results in a maximum transformer fuse clearing time of 2.3 seconds. In a backup mode, the operating time of the negative-sequence element at the source substation is 2.6 seconds, whereas the phase overcurrent at the source substation takes 5.3 seconds to operate.

For a 34.5 kV line-end phase-to-phase fault, the operating time for the negative-sequence element is 3 seconds versus 6.3 seconds for the phase element.

Review of actual relay event reports

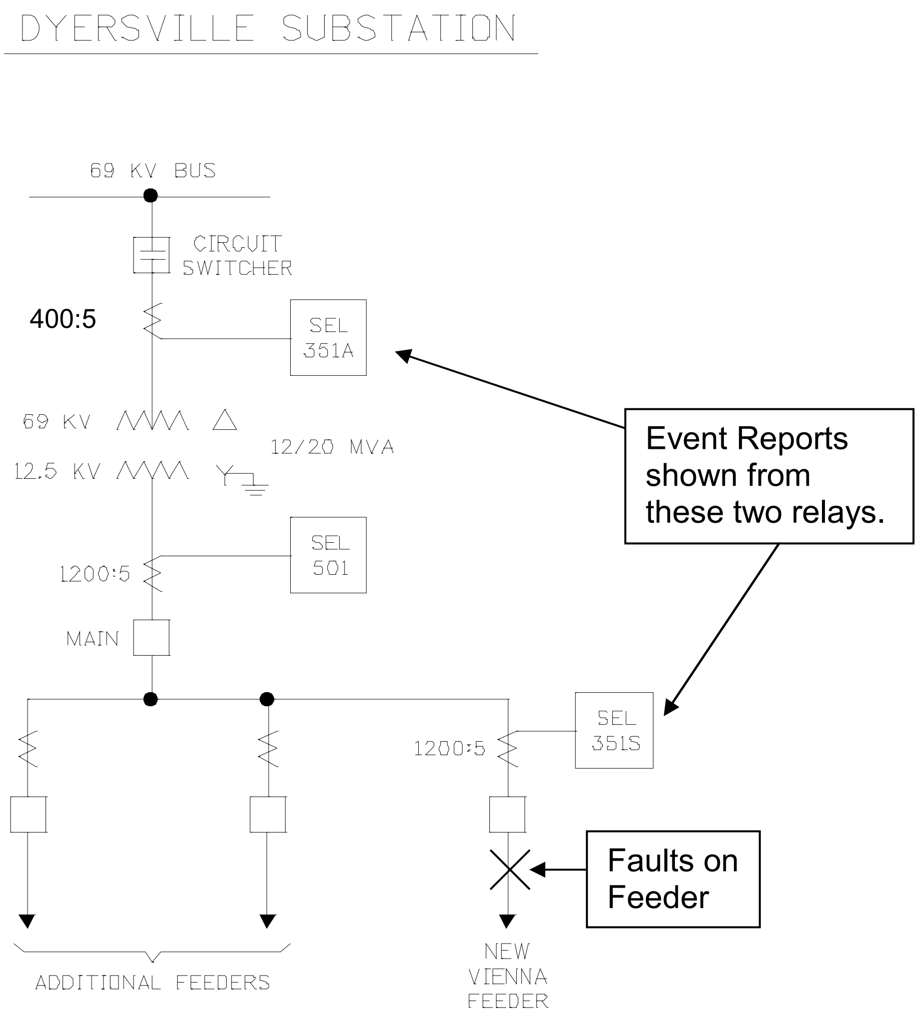

Figure 7 Actual Faults on a Distribution Substation

The actual event reports from the system per Figure 7 show that the initial 12.5 kV fault (phase-to-ground) does not result in pickup of the phase element (51P) on the 69 kV high-side; however the negative-sequence element (51Q) responding to $3I_2$ does get picked up. After the 12.5 kV fault changes to phase-to-phase, both the phase and the negative-sequence elements on the high-side are picked up.

These events show a real-life example of sensitivity improvement by using negative-sequence overcurrents.

```
=>HISTORY (From the Feeder Breaker)
DYERSVILLE 12.5 KV NEW VIENNA

#     DATE      TIME      EVENT   LOCAT  CURR
1  07/05/04 19:56:27.918 BC T      1.50  1684
2  07/05/04 19:56:27.188 CG        1.83  1777
```

Fault starts phase-to-ground

Additional event is triggered when feeder is tripped. Fault has changed to phase-to-phase

```
=>EVENT 2 (PARTIAL EVENT REPORT FOR EVENT #2)
DYERSVILLE 12.5 KV NEW VIENNA, SEL-351S
                             Out  In
      Currents (Amps Pri)    1357 135
    IA    IB    IC    IG     246A 246

[1]  (PREFAULT)
   -14   -35    32   -17     .... 1..
    51   -31   -15     5     .... 1..
    14    35   -32    17     .... 1..
   -51    31    15    -6     .... 1..


[4]  (FAULT BEGINS - SINGLE-PHASE-TO-GROUND)
   -23   -36   348   288     .... 1..
    81   -30   113   164     .... 1..
    30    37 -1013  -945     .... 1..
   -77    31  -305  -350    >...7 1.. (Output #7 asserts for event recorded)
[5]
   -25   -37  1296  1234     ...7 1..
    58   -33   347   372     ...7 1..
    22    35 -1241 -1184     ...7 1..
   -56    32  -348  -372     ...7 1..


 [10]  (FAULT CHANGES FROM SINGLE-PHASE-TO-GROUND TO PHASE-TO-PHASE)
   -19   -36  1134  1079     ...7 1..
    53   -31   211   233     ...7 1..
    18    36 -1062 -1008     ...7 1..
   -54   446  -361    32     ...7 1..
[11]
   -17  -331  1072   723     ...7 1..
    54 -1164   778  -332     ...7 1..
    20   850 -1133  -263     ...7 1..
   -53  1412 -1152   208     ...7 1..
[12]
   -22 -1079  1112    12     ...7 1..
    52 -1373  1296   -25     ...7 1..
    20  1085 -1097     8     ...7 1..
   -53  1372 -1295    24     ...7 1..


Event: CG  Location:    1.83
Currents (A Pri), ABCNGQ:     56  1777  1601     1   206  2705
```

```
Group Settings:
CTR    = 240       PTR    = 60.00     LL     = 8.50
51P1P  = 1.67      51P1C  = U4        51P1TD= 1.80
51G1P  = 1.25      51G1C  = U3        51G1TD= 3.00
51QP   = 2.17      51QC   = U3        51QTD  = 3.00
```

On this feeder, the ground overcurrent is coordinated with all downstream phase devices, so 51Q pickup is set = $\sqrt{3}$ x 51G1P pickup.

```
=>EVENT 1  (PARTIAL EVENT REPORT FOR EVENT #1)
DYERSVILLE 12.5 KV NEW VIENNA, SEL-351S

                              Out  In
      Currents (Amps Pri      1357 135
    IA     IB     IC     IG   246A 246

[4] (TRIP OUPUT ASSERTS)
   -56  1202 -1129    17     ...7 1..
   -11 -1166  1174    -4     ...7 1..
    56 -1186  1109   -21     ...7 1..
    11  1160 -1170     2    >1..7 1..
```

Overcurrent element times out and Output #1 asserts to trip the feeder breaker.

```
 [7] (BREAKER OPENS)
   -43  1168 -1096    29     1..7 1..
    -7 -1032  1031    -9     1..7 1..
    15  -728   676   -38     1..7 ... (Breaker 52a {IN1} opens)
     2   446  -443     6     1..7 ...
[8]
     0   142  -127    14     1..7 ...
    -0    -1    -1    -2     1..7 ...
    -0    -1    -1    -2     1..7 ...
    -0     0     0    -0     1..7 ...

Event: BC T  Location:    1.50
Currents (A Pri), ABCNGQ:     55  1684  1637     2    19  2796
```

Phase B Current

Phase C Current

$3I_2$ Current

```
=>HISTORY (From Delta-Wye Transformer High-Side Circuit Switcher)
DYERSVILLE 69 KV WEST XFMR CIRCUIT SWITCHER

#     DATE      TIME     EVENT   LOCAT  CURR
1  07/05/04 19:56:27.199 BC      20.52   378


=>EVENT 1  (PARTIAL EVENT REPORT)
DYERSVILLE 69 KV WEST XFMR CIRCUIT SWITCHER

                            Out  In      51
      Currents (Amps Pri)   1357 135     PQ
    IA    IB    IC    IG    246A 246
[1]  (PREFAULT)
   -26    22     4    -0    .... .b..    ..
   -10   -21    31    -0    .... .b..    ..
    26   -22    -4     0    .... .b..    ..
    10    21   -31    -0    .... .b..    ..

[3]  (FAULT BEGINS - SINGLE-PHASE-TO-GROUND ON LOW-SIDE)
   -26    21     4    -0    .... .b..    ..
   -12   -35    47     0    .... .b..    ..
    28   -62    35     1    .... .b..    ..
    13    76   -89    -0    .... .b..    ..
[4]
   -28   122   -94    -0    .... .b..    ..
   -11   -99   110     0    .... .b..    ..
    28  -136   108     0    .... .b..    .p
    11    94  -105    -0   >...7 .b..    .p (Out #7 asserts for event recorded)
```

51Q picks up for low-side phase-to-ground fault

```
[9]  (LOW-SIDE FAULT CHANGES FROM SINGLE-PHASE-TO-GROUND TO LINE-TO-LINE)
   -27   122   -95    -0    ...7 .b..    .p
   -10   -92   103     0    ...7 .b..    .p
    27  -117    90     0    ...7 .b..    .p
    10    90  -101    -0    ...7 .b..    .p
[10]
   -52   140   -87     0    ...7 .b..    .r
   -34   -48    82     0    ...7 .b..    .r
   135  -253   118    -1    ...7 .b..    .r
    43    11   -54    -0    ...7 .b..    pr
[11]
  -198   358  -159     1    ...7 .b..    pp
   -24   -12    36     0    ...7 .b..    pp
   207  -378   170    -1    ...7 .b..    pp
    20     9   -29    -0    ...7 .b..    pp
```

51P only picks up after low-side fault changes to phase-to-phase

```
Event: BC  Location:   20.52
Currents (A Pri), ABCNGQ:    209   378   172     0     0   526

Group Settings:
CTR   = 80        PTR   = 600.00
Z1MAG = 1.00      Z1ANG = 90.00    Z0MAG = 1.00     Z0ANG = 90.00
LL    = 1.00

51P1P = 2.40      51P1C = U4       51P1TD= 7.00
51G1P = 0.50      51G1C = U4       51G1TD= 0.50
51QP  = 2.20      51QC  = U3       51QTD = 9.00
```

Review of actual relay meter data

Normally negative-sequence current is significantly less than load current. A meter command in this case shows an I_2/I_1 ratio of approximately 3% ({5.5 Amps of $3I_2/3$}/49 Amps of I_1). Due to the delta winding configuration, there is no zero-sequence flow.

```
=>METER
DYERSVILLE 69KV WEST XFMR
                A         B         C         N         G
I MAG (A)       47.893    49.219    50.985    0.164     0.188
I ANG (DEG)    -13.07    -129.55    107.29   -169.84    -32.40
                A         B         C         S
V MAG (KV)      40.645    40.607    40.767    0.013
V ANG (DEG)     0.00     -119.71    120.14   -60.47
                A         B         C         3P
MW              1.896     1.969     2.027     5.892
MVAR            0.440     0.341     0.462     1.244
PF              0.974     0.985     0.975     0.978
                LAG       LAG       LAG       LAG

                I1        3I2       3I0       V1        V2        3V0
MAG             49.347    5.569     0.188     40.673    0.107     0.053
ANG    (DEG)   -11.77    -156.99   -32.40     0.14     -115.03   -14.35
```

Conclusion

Negative-sequence overcurrents provide many added benefits. The examples clearly show the necessary steps to take in properly setting the elements. The increased use of the negative-sequence function is a "win-win" proposition.

Bibliography

[1] A.F. Elneweihi, E.O. Schweitzer, III, and M.W. Feltis, "Negative-Sequence Overcurrent Element Application and Coordination in Distribution Protection", IEEE Transactions on Power Delivery, Vol. 8, No. 3, July 1993, pp. 915 – 924.

[2] A.F. Elneweihi, E.O. Schweitzer, III, and M.W. Feltis, "Improved Sensitivity and Security for Distribution Bus and Feeder Relays." Proceedings of the 18th Annual Western Protective Relay Conference, Spokane, Washington, October 1991.

[3] F. Calero, "Rebirth of Negative-Sequence Quantities in Protective Relaying with Microprocessor-Based Relays." Proceedings of the 30th Annual Western Protective Relay Conference, Spokane, Washington, October 2003.

Bibliography

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Back to Table of Contents