A Novel Generator Distance Backup Protection Element

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***Abstract*—Generator protective relays usually provide a backup distance protection element to protect the machine in the event of an uncleared system fault. The zone of coverage of the backup distance element begins at the generator terminals and extends into the power system through the delta-wye generator step-up transformer (GSU). The element is designed to account for transformer winding connections to provide an accurate reach for phase-to-phase and three-phase faults. However, due to the open circuit that the GSU introduces in the zero-sequence network, a generator backup distance element cannot accurately detect system ground faults by using the generator terminal voltages and currents.**

This paper describes a novel distance element that provides accurate reach for both phase and ground faults on the system side of the transformer. The element uses currents and voltages measured at the generator terminals along with the current from the grounded neutral connection of the GSU system-side winding.

The presented element used to compensate the measured voltages and currents works for any implementation of a distance element.

I. Introduction

Generator protection schemes include backup protection elements that respond to external faults that are not cleared within the required time by system protection elements. Throughout the paper, we define the system as the high voltage (HV) transmission network and the zone of coverage of a distance function as its reach. The reach of these protection elements is an application decision. Close-in faults are the most stressful to the protected machine and are easy to detect. Detecting remote faults may be more problematic due to the infeed effect, but these faults stress the protected machine to a lesser degree. Once their reach is selected, these protection elements are time coordinated, giving the system protection schemes time to operate first. Many factors impact the application of backup protection including protection redundancy, use of breaker failure protection, and bus configuration.

In general, backup protection schemes can be subdivided into local and remote [1]. Generator and transmission system protection schemes typically reside in distinct locations, with the former being in the powerhouse and the latter in the switchyard. Even though the generator main breaker may be in the switchyard, generator backup protection can be considered as remote system backup protection in most other regards.

Fig. 1 shows the generator protection elements that can protect against external faults.

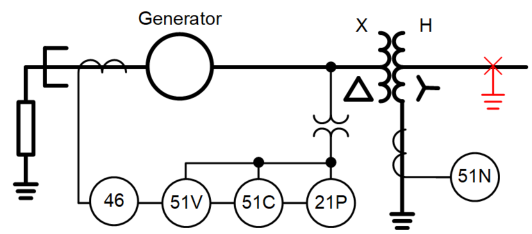


Fig. 1. Generator backup protection elements.

The stator current unbalance (46) element protects against rotor overheating due to the negative-sequence component in the stator currents. Negative-sequence current is produced both by shunt failures (short circuits) and series failures (open-phase conditions). We select the element operating curve and time-dial setting according to the negative-sequence withstand capability of the generator. The element does not respond to three-phase faults because there is no negative-sequence current, and the element may have a long operating time for low-magnitude unbalanced faults.

Generator fault current decays as the generator's equivalent impedance transitions from sub-transient to transient and finally to synchronous. The steady-state fault current may be less than the rated current, which complicates the application of a simple overcurrent element for backup protection. The 51C and 51V elements were commonly found in early electromechanical generator protection schemes and are still applied today. Both the 51C and 51V elements use a voltage measurement to restrain or control an overcurrent element. This allows for an application of a more sensitive current pickup setting for these elements, thereby achieving more dependable operation.

Fig. 1 also shows an inverse-time overcurrent (51N) element located at the neutral-ground connection of the generator step-up transformer (GSU). The 51N element provides backup protection for an uncleared system fault involving ground. Because transmission systems are practically balanced networks, this element measures insignificant current under normal operation and can therefore provide sensitive backup protection for system ground faults. The 51N element benefits from a simple and robust operating principle that requires only a single current measurement. It is generally implemented within the generator/GSU protection scheme.

The use of the 21P element for backup protection is popular for the following reasons:

- With the advent of digital generator protection, the 21P element no longer has a significant incremental cost over the 51V or 51C.

- Distance elements have a well-defined characteristic in the RX plane and a fixed time delay. Coordinating a generator distance element with the commonly applied system distance elements is easier than coordinating it with an inverse-time overcurrent element.
- Plotting the impedance characteristics of various distance elements on the same RX diagram is a convenient and common practice.

Generators connect to the system through a GSU transformer. The GSU transformer is always delta-connected on the generator (LV) side as shown in Fig. 1. The delta connection isolates the generator zero-sequence network from the transmission system zero-sequence network. This allows the generator neutral to be grounded through a high impedance, limiting damage for ground faults and allowing the use of generator ground fault protection schemes that cover the entire stator winding.

This paper is organized as follows. Section II discusses the limitations to system ground fault coverage provided by generator distance elements reaching through a delta-wye transformer. Section III presents the new generator backup ground distance (21G) element that uses the GSU neutral current, in addition to the generator voltages and currents, to provide accurate coverage for system ground faults. Section IV provides a numerical example to support the understanding of this new 21G element. The new element requires the transformer zero-sequence impedance (Z_{0T}), which is not a commonly available parameter. Section V discusses how Z_{0T} can be obtained and shows how an error in Z_{0T} has a modest impact on the 21G element reach inaccuracy. The resultant reach inaccuracy is well within typical margins used to set the reach of distance relays. Section VI discusses application guidelines for the new 21G element and compares its performance with the currently used 51N element, noting how the two elements can complement each other to provide optimal backup protection for system ground faults. Appendix A supports Section II by presenting equations for the apparent impedance measured by a distance relay reaching through a GSU. Appendix B supports Section III by presenting analysis related to the development of the new 21G element. Appendix C supports Section VI by discussing settings guidelines to help ensure coordination of the new 21G element with line distance protection for an example system. Appendix D supports Section VI by comparing the performance of the new 21G element with the 51N element for the example system.

II. Fault Coverage Through a Delta-Wye Transformer

Equations (1) and (2) calculate the loop impedances of a phase distance (21P) element and a ground distance (21G) element, respectively.

$$Z_{LOOP\_PP} = \frac{V_{PP}}{I_{PP}} \tag{1}$$

$$Z_{LOOP\_PG} = \frac{V_{PG}}{I_P + 3k_0 I_0} \tag{2}$$

where k_0 is the zero-sequence compensation factor for the transmission line.

We first consider phase-to-phase faults beyond the GSU transformer. Fig. 2 shows the connections for a YNd1 transformer.

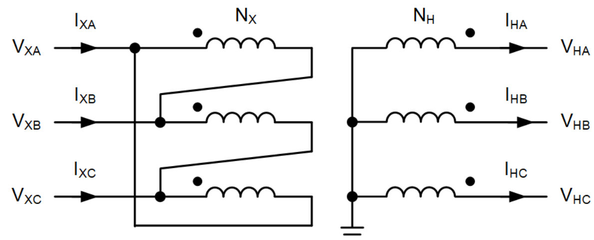


Fig. 2. Sample GSU transformer connection diagram (YNd1) and relay measurements.

Using the figure, we write the compensated faulted loop equations for voltage and current for (1) as presented in (3) and (4) [2]. These equations are written in matrix form. Considering the AB loop of a phase distance element at the HV terminals and using Fig. 2, we note that V_{HAB} corresponds to $V_{XAB} - V_{XBC}$. We also note that $-I_{HA} + I_{HB}$ corresponds to I_{XB}. Repeating the exercise for the remaining loops fills out the matrices in (3) and (4). Similar matrices can be written for other transformer connections.

$$\begin{bmatrix} V_{AB\_COMP} \\ V_{BC\_COMP} \\ V_{CA\_COMP} \end{bmatrix} = \frac{N_H}{N_X} \bullet \begin{bmatrix} 1 & -1 & 0 \\ 0 & 1 & -1 \\ -1 & 0 & 1 \end{bmatrix} \bullet \begin{bmatrix} V_{XAB} \\ V_{XBC} \\ V_{XCA} \end{bmatrix} \tag{3}$$

$$\begin{bmatrix} I_{AB\_COMP} \\ I_{BC\_COMP} \\ I_{CA\_COMP} \end{bmatrix} = -\frac{N_X}{N_H} \bullet \begin{bmatrix} 0 & 1 & 0 \\ 0 & 0 & 1 \\ 1 & 0 & 0 \end{bmatrix} \bullet \begin{bmatrix} I_{XAB} \\ I_{XBC} \\ I_{XCA} \end{bmatrix} \tag{4}$$

Auxiliary voltage transformers (VTs) and current transformers (CTs) can be used for compensation, or the 21P element can implement the compensation. Equations (3) and (4) effectively move the 21P element to the H terminal of the GSU transformer, as shown in Fig. 3(a).

We cannot apply similar compensations for the ground loop equation in (2) because the generator voltages and currents are missing the zero-sequence voltage and current components from the transmission network. However, we can investigate the effectiveness of the 21P element for ground faults in the transmission network. To this end, we consider the sequence network for a system ground fault with a 21P element located at the HV terminals of the GSU transformer.

In [3] and [4], equations are developed to calculate the phase distance loop impedances for the ground fault of Fig. 3(b) as a function of network impedances, current distribution factors (C1, C2, C0), and fault location (m). Appendix A summarizes these equations.

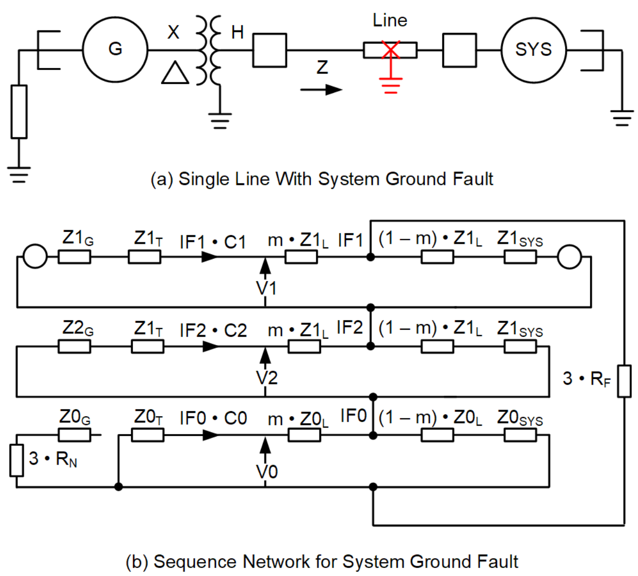


Fig. 3. Sequence network for a phase-to-ground system fault.

We plot Z_{AB} and Z_{CA} for an AG fault in Fig. 4 and Fig. 5 by using the equations in Appendix A. Note that the Z_{BC} loop (not shown) does not respond to an AG fault. The plots use the parameters from the example system in Appendix C for this exercise and are plotted for fault resistances of 0 and 10 ohms primary. Straight line segments terminating at Z_{GSU} and Z_{LINE} indicate the GSU transformer and line impedances, and the mho characteristics representing two static distance zones are superimposed onto the plots. Both zones originate at the generator terminals. The inner zone is set at half of the impedance of the GSU transformer, and the outer zones overreach the line by 20 percent.

Fig. 4 shows the case of the line in service. It is evident that the phase distance element does not detect ground faults for the example system with the remote breaker closed.

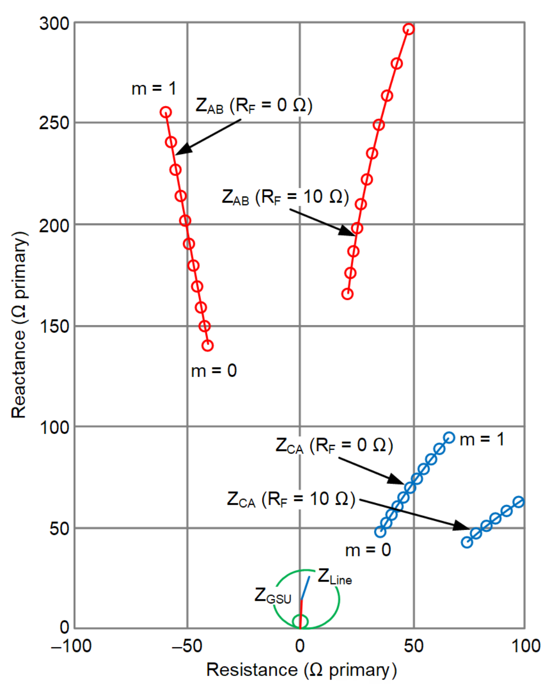


Fig. 4. 21P element loop impedances for an AG fault with the remote breaker closed for the example power system of Appendix C.

It is likely that the protection at the remote terminal remains healthy and a remote underreaching element responds to the fault and trips the remote breaker. When the remote breaker opens, the loop impedance loci move in towards the impedance characteristic, but the phase distance element still only operates for a fault very close to the HV terminal of the GSU transformer, as shown in Fig. 5.

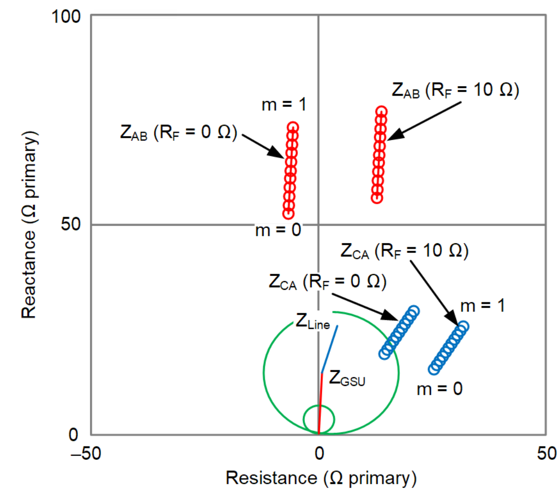


Fig. 5. 21P element loop impedances for an AG fault with the remote breaker opened for the example power system of Appendix C.

III. A New Generator Backup Ground Distance Element

A generator protective relay measures stator voltages and currents, i.e., voltages and currents at the delta side of the GSU transformer. The relay often also measures the current in the neutral connection of the GSU transformer's wye side (see Fig. 2). Assuming the GSU transformer is healthy, we can transfer the delta-side measurements to the wye side (i.e., calculate the wye-side voltages and currents by using the delta-side voltages and currents and basic transformer data). We then use the obtained wye-side voltages and currents to excite the standard ground distance element logic to obtain ground distance protection in a generator protective relay. Traditionally, the reach of the generator phase distance backup element starts at the delta-side of the GSU transformer. We follow this approach and further modify the new element input voltages and currents to move the obtained wye-side voltages and currents from the wye side to the delta side (in terms of the GSU transformer ratio and to include the positive-sequence impedance of the GSU transformer inside the zone). This way, the traditional phase distance backup element and the new ground distance backup protection element both work with the delta-side voltages and currents, have their reach starting at the delta side, and use impedances that are on the delta-side base.

We derive the equations for the distance element input voltages and currents in Appendix B. Note that in this section and in Appendix B, the compensated voltages and currents that pass to the distance element use only phase designators in their subscripts as shown on the left side of (5) and (6) and on the right side of Fig. 6.

Equations (5) and (6) calculate these compensated voltages and currents.

$$\begin{aligned} V_A &= V_{XA} - V_{XB} + I_{COMP} \bullet Z_{COMP} \\ V_B &= V_{XB} - V_{XC} + I_{COMP} \bullet Z_{COMP} \\ V_C &= V_{XC} - V_{XA} + I_{COMP} \bullet Z_{COMP} \end{aligned} \quad (5)$$

$$\begin{aligned} I_A &= I_{XA} - I_{XB} + I_{COMP} \\ I_B &= I_{XB} - I_{XC} + I_{COMP} \\ I_C &= I_{XC} - I_{XA} + I_{COMP} \end{aligned} \quad (6)$$

where the compensating current is:

$$I_{COMP} = \frac{V_H}{V_X} \bullet \frac{I_{HN}}{\sqrt{3}} \quad (7)$$

and the compensating impedance factor is:

$$Z_{COMP} = Z_{1T} \bullet (3 \bullet k_0 + 1) - Z_{0T} \quad (8)$$

where:

V_H and V_X are nominal wye- and delta-side line-to-line voltages, respectively.

k_0 is the ground distance protection zero-sequence compensating factor selected based on the line impedances.

Z_{1T} and Z_{0T} are the positive- and zero-sequence impedances, respectively, of the GSU transformer on the delta-side base.

As expected, the compensating equations only require phase-to-phase voltages, and the element works with both wye- and delta-connected voltage transformers.

Fig. 6 shows the signal flow chart representing the compensation equations. The compensation is simple and involves subtracting or adding signals and developing one voltage drop from one of the currents calculated in (7) through a replica impedance calculated in (8).

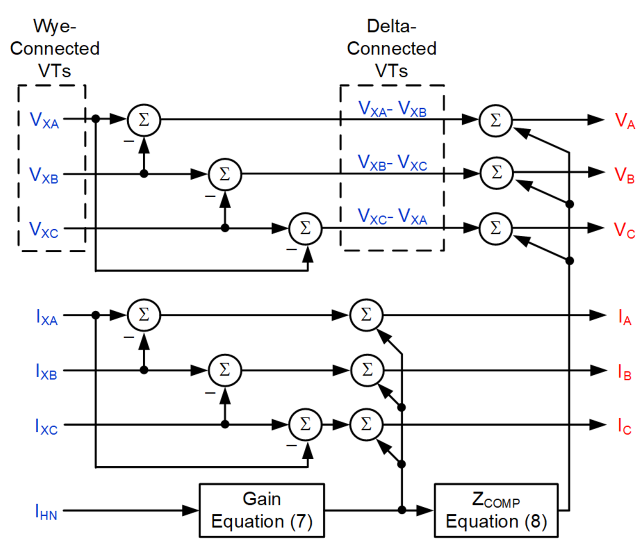


Fig. 6. Signal flowchart of the compensation element with inputs in blue and outputs to the distance function in red.

Equations (5) and (6) and the flowchart in Fig. 6 are written for phasors, but the voltage and current phasors can be directly replaced by voltage and current samples by using the concept of a replica impedance applied to the Z_{COMP} current multiplier. The solution is therefore completely general, allowing any of the standard ground distance protection elements to be employed, including those based on instantaneous samples.

A. Ground Distance Element

We use voltages and currents calculated in (5) and (6), respectively, to excite a standard ground distance element logic to provide backup protection for ground system faults. We focus on ground distance protection because it is a novel application.

When excited with the voltages and currents calculated in (5) and (6), respectively, the ground distance element uses the following:

- The selected zero-sequence compensation factor (k_0) following the standard practice of distance protection. When calculating the desired k_0, disregard the transformer impedances (they are already accounted for). Typically, k_0 reflects the line Z_0/Z_1 ratio.
- The reach impedance expressed on the delta-side base, including the transformer positive-sequence impedance (the reach starts at the stator terminals).
- A mho or quadrilateral operating characteristic according to the coordination needs.

If the ground distance element uses a quadrilateral operating characteristic, the ground protection element can be set to use the following:

- A resistive reach for proper coordination with downstream ground distance elements.
- A polarizing quantity for the reactance comparator (zero-sequence current, negative-sequence current, or loop current) to optimize coordination with downstream ground distance elements.

Note that (6) calculates the distance element input currents, not the ground loop currents. We use these input currents for faulted-loop selection, overcurrent supervision, and other internal applications in a typical distance element logic. The loop currents include the zero-sequence compensation factor k_0 according to the principles of ground distance protection. For example, (9) calculates the compensated AG loop current:

$$I_{AG} = I_A + k_0 \bullet 3I_0 = I_{XA} - I_{XB} + I_{COMP} \bullet (3k_0 + 1) \quad (9)$$

Similarly, (5) calculates the distance element input voltages. These input voltages can be used for polarization (self-, cross-, or memory-polarization). Memory polarization in generator applications may be detrimental due to possible large frequency excursions. Memory polarization is not strictly needed because the delta-side voltages during a transmission line fault are never zero due to the impedance of the GSU transformer, even for close-in, metallic, three-phase faults in the system.

The ground distance element can be self-polarized, or it can use a concept of an offset impedance and evaluate backwards up to a fraction of the stator impedance.

B. Phase Distance Element

Note that (5) and (6) replicate the wye-side voltages and currents and as such apply to both ground and phase distance elements. For example, we can calculate the AB loop quantities from (5) and (6) and obtain the AB loop voltage and the AB loop current by using (10) and (11), respectively.

$$\begin{aligned} V_{AB} &= V_A - V_B \\ &= \left(V_{XA} - V_{XB} + I_{COMP} \cdot Z_{COMP}\right) \\ &\quad - \left(V_{XB} - V_{XC} + I_{COMP} \cdot Z_{COMP}\right) \\ &= V_A - 2 \cdot V_B + V_C \end{aligned} \tag{10}$$

$$\begin{aligned} I_{AB} &= I_A - I_B \\ &= \left(I_{XA} - I_{XB} + I_{COMP}\right) - \left(I_{XB} - I_{XC} + I_{COMP}\right) \\ &= I_A - 2 \cdot I_B + I_C \\ &= -3 \cdot I_B \end{aligned} \tag{11}$$

Equations (10) and (11) are a part of the "phase distance element looking through a power transformer" principle in relation to a delta-wye transformer. It is evident that the zero-sequence compensation terms are canceled out in (10) and (11). These equations demonstrate that the compensation remains valid for the 21P element. The signal flowchart in Fig. 6 can be viewed as a standard processing component that is inserted ahead of a distance function. In other words, to properly detect an AB fault in the system, a generator phase distance element uses the loop voltage (10) and current (11). The compensating equations (5) and (6) solve the problem of evaluating the ground and phase distance elements in a power transformer.

C. *Summary of the New Element*

The new element uses phase-to-phase voltages and currents on the delta side of the GSU transformer, as well as the current in the neutral of the wye side, to derive phase voltages and currents that accurately replicate the wye-side phase quantities calculated in (5) and (6).

The element requires the positive- and zero-sequence impedances of the GSU transformer. These impedances are readily available from the short-circuit program database.

The zero-sequence impedance can be calculated by using an event record for a system ground fault ($Z_{0T} = -3V0 / 3I0$) with no other local sources feeding the fault. The calculation also requires the fault information from the transmission line relay. The voltages and currents would be measured at the generator terminals. Section V includes a discussion on the determination of Z_{0T} through field testing.

The element requires the zero-sequence compensation factor (k_0), but that value is already a setting of the standard ground distance element. If multiple zones of ground distance protection are used with different k_0 factors, the voltage calculations in (5) perform independently for each zone.

The element works for both ground and phase elements. We can use the standard distance logic with voltages (5) and currents (6) and obtain performance essentially equivalent to having a distance relay on the wye side of the GSU transformer. There are two notable differences: 1) an internal transformer fault appears as a forward fault to the new 21G element, and 2) a three-phase fault at the transformer terminals would not be a zero-voltage fault that would otherwise require voltage memory for dependable operation.

Equations (5) and (6) apply to the GSU transformer in Fig. 2 (YNd1 connection). Obtain the equations for any other delta-wye GSU transformer (e.g., YNd11) by rotating the indices in (5) and (6). The simple rule is to select the phase-to-phase voltage or current for the phase pair on the delta side that is on the same core leg as the phase on the wye side of the transformer (while paying attention to winding polarity marks). For example, the A-phase coil on the wye side in Fig. 2 is on the same leg as the coil connected between the A- and B-phases on the delta side; hence, (5) and (6) use the difference between the A and B voltages and currents in equations for the compensated A-phase. Also, we can use (5) and (6) for any delta-wye transformer, and the distance element works correctly, except for faulted-phase targeting.

D. *Accounting for GSU and Instrument Transformer Ratios*

The element uses stator voltage and current measurements, and therefore it naturally follows the delta-side transformer base and the delta-side instrument transformer base for secondary units. When setting the element, obtain the transformer and line impedances on the delta-side base of the GSU transformer and convert them to secondary units by using the voltage and current ratios of the stator voltages and currents. Of course, the neutral-point current, I_{HN}, uses a different CT ratio (CTR_{HN}) than the stator currents (CTR_X). In secondary amperes, use (7) as follows:

$$I_{COMP(SEC)} = \frac{V_{HNOM}}{V_{XNOM}} \cdot \frac{I_{HN(SEC)}}{\sqrt{3}} \cdot \frac{CTR_{HN}}{CTR_X} \tag{12}$$

Replace (7) with (12), and you can use (5) and (6) in secondary units.

IV. Numerical Example

Consider the system in Fig. 7 and the following data:

Transformer: 13.8/138 kV, 200 MVA, YNd1, 15%.

Line: $Z_{1L} = 12.54\ \Omega\angle 71.6°$, $Z_{0L} = 37.64\ \Omega\angle 79.6°$.

Fault: ABG, 0.95 pu from the GSU transformer.

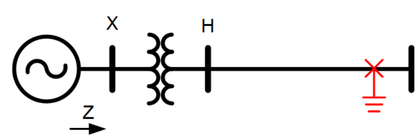


Fig. 7. Numerical example system.

In this example, the source on the left is modeled as a synchronous generator with typical parameters and the GSU transformer is modeled as a three-phase bank. The distance element measures the voltages and currents listed in Table I:

Table I
Distance Element Measurements

	A	B	C
V_X (kV)	2.227∠0°	2.308∠–74°	3.624∠142.2°
I_X (kA)	15.74∠17.6°	8.96∠–154.5°	6.97∠–172.6°

The neutral point current is $I_{HN} = 1.78\ kA\angle -137.3°$.

Equation (13) calculates the positive-sequence impedance of the GSU transformer on the delta-side base.

$$X_{1T} = 0.15 \cdot \frac{13.8^2}{200} = 0.1428\ \Omega \tag{13}$$

To account for any potential sources of error from our model, we have performed the positive-sequence short-circuit test in our model and measured the positive-sequence impedance of the GSU transformer on the delta-side base as:

$$Z_{1T} = 0.1438\ \Omega\angle 87.9° \tag{14}$$

Note that the nameplate and the measured Z_{1T} values differ by 0.7 percent, and we use this measured value in our calculations.

We have performed the zero-sequence short-circuit test in our model ($Z_{0T} = -3V0 / 3I0$ as described in Section III.C) and obtained the following zero-sequence impedance of the GSU transformer on the delta-side base:

$$Z_{0T} = 0.1216\ \Omega\angle 87.9° \tag{15}$$

Using Z1L and Z0L we get the line k_0 factor of:

$$k_0 = 0.6715\angle 12° \tag{16}$$

We use (8) and calculate the compensating impedance:

$$Z_{COMP} = 0.3086\ \Omega\angle 99.2° \tag{17}$$

We use (7) and calculate the compensating current:

$$I_{COMP} = 10.28\ \text{kA}\angle -137.3° \tag{18}$$

We use (5) and (6) to calculate the compensated voltages and currents at the generator terminals as shown in Table II.

TABLE II
COMPENSATED VOLTAGES AND CURRENTS

	A	B	C
V (kV)	4.101∠3.6°	8.773∠–46.8°	2.602∠174.2°
I (kA)	15.62∠6.0°	13.22∠–131.3°	32.07∠–156.7°

Next, we calculate the loop voltages, currents, and apparent impedances as shown in Table III.

TABLE III
LOOP VOLTAGES, CURRENTS, AND APPARENT IMPEDANCES

	AG	BG	AB
V_L (kV)	4.101∠3.6°	8.773∠–46.8°	6.926∠106°
I_L (kA)	15.67∠–76.8°	33.91∠–127.7°	26.89∠25.5°
Z (Ω)	0.2617∠80.5°	0.2588∠80.8°	0.2576∠80.5°

The ABG fault type is conveniently chosen to allow three faulted loops (one phase and two ground) to be checked simultaneously. A practical distance element implementation secures the ground loops for this fault type because these loops can overreach for resistive faults.

The expected apparent impedance is the sum of the positive-sequence impedance of the GSU transformer and the positive-sequence impedance of the line between the GSU transformer and the fault. Equation (19) calculates the latter impedance on the delta-side base.

$$\begin{aligned} Z_{FLT} &= 0.95 \cdot 12.54\ \Omega\angle 71.6° \cdot \left(\frac{13.8}{138}\right)^2 \\ &= 0.1192\ \Omega\angle 71.6° \end{aligned} \tag{19}$$

Therefore, the expected apparent impedance is:

$$Z_{APP} = 0.2594\ \Omega\angle 80.5° \tag{20}$$

Comparing (24) with Table III, we see that the apparent impedances that the relay measures in the AG, BG, and AB loops match the expected apparent impedance. The errors are 1.1, 0.5, and 1.0 percent for the AG, BG, and AB loops, respectively. These small errors result from the uncertainty of line and transformer parameters and because our compensation element neglects the transformer magnetizing current.

V. SHORT-CIRCUIT IMPEDANCE OF THE GSU TRANSFORMER CONSIDERATIONS

A. *Determination of Short-Circuit Impedance*

The leakage inductance of a transformer is the inductance associated with the stray flux (i.e., the flux that does not couple between the windings). This inductance along with the winding resistance forms the short-circuit impedance, Z_{1T}, so called because it limits the fault current through the transformer. In two-winding transformers, the short-circuit impedance is listed as a single number. It is commonly found on the nameplate and expressed in percentage. The positive- and negative-sequence short-circuit impedances are equal.

For single-phase banks, Z_{0T} is equal to Z_{1T}. Otherwise, Z_{0T} depends on the transformer construction (core- or shell-type), the winding location, and the winding connection (presence of the delta winding) [5].

A three-limb, core-type transformer without a delta winding has no return path for the zero-sequence flux through the core, so Z_{0T} can be quite high (75 to 200 percent of Z_{1T}). A five-limb, core-type transformer without a delta winding has a return path through the core, so Z_{0T} corresponds to the magnetizing impedance of the transformer. A shell-type or three-phase transformer made with three single-phase units is similar.

For transformers with a delta winding, the circulating current within the delta creates a flux opposing that produced by the wye-winding. So, the deviation of Z_{0T} from Z_{1T} depends mainly on the leakage flux between the windings.

IEC 60076-8 [6] provides the typical range of Z_{0T} for two-winding transformers, as shown in Table IV. Note that Table IV assumes that the windings are concentrically wound on the core. We can see from Table IV that Z_{0T} is a percentage of Z_{1T} and is dependent on the wye-winding's location (innermost or outermost) on a three-limb core. The winding location affects the proportion of zero-sequence flux linking through the core. Note that for a GSU transformer, the wye-winding is the outermost winding.

TABLE IV
TYPICAL ZERO-SEQUENCE IMPEDANCE RANGE FOR WYE-DELTA TRANSFORMERS

Wye-Winding Location on the Core	**Three-Limb Core-Type**
Outer (HV)	$a_1 \bullet Z_{1T}$
Inner (LV)	$a_2 \bullet Z_{1T}$

$0.8 < a_1 < a_2 < 1.0$

Z_{1T} = Short-circuit positive-sequence impedance

Z_{1T} is usually available from the transformer nameplate or manufacturer test reports, but Z_{0T} might not be readily available [7]. Field or factory testing can determine the short-circuit impedances. Utilities carry out such tests for protection coordination and system modeling purposes.

IEC 60076-1 [8] and IEEE C57.12.90 [9] provide guidance on impedance testing of transformers. Fig. 8 shows the test setup for a delta-wye transformer. For the positive-sequence test, the injection source is applied to one terminal of the wye winding at a time. For the zero-sequence test, the three terminals at the wye are shorted. The three terminals at the delta connection can be left open, which is common, or can be shorted. A single-phase voltage is applied, and the voltage (V_{INJ}), current (I_{MEAS}), and power (P_{MEAS}) are measured as shown in Fig. 8.

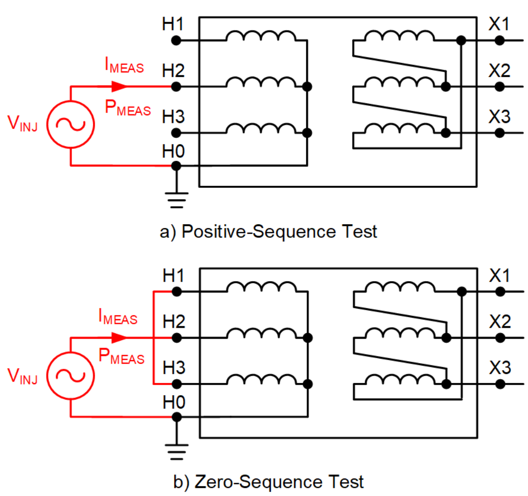


Fig. 8. Short-circuit impedance test setup (test connections shown in red) for a three-phase delta-wye-connected transformer.

From the measured quantities, we calculate the zero-sequence impedance magnitude by using (21).

$$Z_{0\_MAG} = \frac{3 \bullet V_{INJ}}{I_{MEAS}} \tag{21}$$

The zero-sequence impedance is also converted to a percentage of the rated impedance of the wye winding. The measured and calculated quantities are included in the test report.

Although impedance angles are not part of the IEC or IEEE testing standards, they can be calculated using (22) if P_{MEAS} is available.

$$Z_{0\_ANG} = \tan^{-1}\left(\sqrt{\left(\frac{V_{INJ} \bullet I_{MEAS}}{P_{MEAS}}\right)^2 - 1}\right) \tag{22}$$

B. *Typical Values*

The new distance element requires magnitude and angle values for both Z_{1T} and Z_{0T}. Ideally, these should be measured via testing according to the previous section. Test sets are commercially available and are both convenient to use and accurate.

As previously mentioned, the Z_{1T} angle measurement is not a required test but this value is typically quite close to 90 degrees. In some cases, the magnitude and angle of Z_{0T} are not available because the zero-sequence test was not carried out. In lieu of testing, the Z_{0T} magnitude can be estimated as $0.9 \bullet Z_{1T}$ [5].

The typical angle of Z_{0T} is arguably the least well-known transformer impedance parameter. From the limited data available to the authors, such as [10], this angle is expected to be a few degrees lower than the angle of Z_{1T}.

Section V.C characterizes the inaccuracies in the reach of the new 21G element due to potential errors in the transformer impedance data.

C. *Error Analysis Regarding Transformer Impedance Settings*

Errors in the transformer impedance values, which are typically well within margins used to develop protection settings (as described in Appendix C), have a small impact on the 21G element reach. The following analysis provides the proof and an upper bound for the 21G element reach error.

The relative (percentage) error in the impedance measurement (δZ) is the sum of the relative errors in the loop voltage (δV) and the loop current (δI):

$$\delta Z = \delta V + \delta I \tag{23}$$

The current-compensating equations of (6) do not use transformer impedances, and therefore inaccuracies in the impedances do not impact the compensated currents ($\delta I = 0$).

We estimate the sensitivity of the phase-to-ground voltage to inaccuracies in the transformer impedances by using the derivative of (5) respective to Z_{0T} and Z_{1T}:

$$\left|\frac{dV_A}{dZ_{0T}}\right| = |I_{COMP}| \tag{24}$$

$$\left|\frac{dV_A}{dZ_{1T}}\right| = |3 \bullet k_0 \bullet I_{COMP}| \tag{25}$$

We can re-write (24) and (25) to obtain the relative voltage error as follows:

$$\delta V = \left|\frac{dV_A}{V_A}\right| = \left|\frac{I_{COMP}}{V_A}\right| \bullet |dZ_{0T}| \tag{26}$$

$$\delta V = \left|\frac{dV_A}{V_A}\right| = \left|\frac{I_{COMP}}{V_A}\right| \bullet |3 \bullet k_0| \bullet |dZ_{1T}| \tag{27}$$

For single-line-to-ground faults, the faulted-phase voltage is not lower than the zero-sequence component in that voltage. The latter is the compensating voltage in (5), as calculated in (28).

$$V_0 = I_{COMP} \bullet Z_{COMP} \quad (28)$$

We can therefore write:

$$|V_A| > |I_{COMP} \bullet Z_{COMP}| \quad (29)$$

Equation (29) is the worst-case scenario for considering the relative voltage error because it considers only the zero-sequence component in the faulted-phase voltage. We insert (29) into (26) and (27) to obtain:

$$\delta V < \left|\frac{1}{Z_{COMP}}\right| \bullet |dZ_{0T}| = \left|\frac{Z_{0T}}{Z_{COMP}}\right| \bullet \left|\frac{dZ_{0T}}{Z_{0T}}\right| \quad (30)$$

$$\delta V < \left|\frac{3k_0}{Z_{COMP}}\right| \bullet |dZ_{1T}| = |3k_0| \left|\frac{Z_{1T}}{Z_{COMP}}\right| \bullet \left|\frac{dZ_{1T}}{Z_{1T}}\right| \quad (31)$$

We estimate errors and therefore can replace k_0 with a typical value of 0.67∠0°. We also use (8) to simplify the impedance ratios in (30) and (31). If we assume that Z_{0T} is close to Z_{1T} (about 0.9 of Z_{1T}) and we use a typical value of k_0, we obtain:

$$\left|\frac{Z_{1T}}{Z_{COMP}}\right| \cong \left|\frac{Z_{0T}}{Z_{COMP}}\right| \cong 0.5 \quad (32)$$

We insert (32) in (31) and write:

$$\delta Z < 0.5 \bullet \delta Z_{0T} \quad (33)$$

$$\delta Z < \delta Z_{1T} \quad (34)$$

Equations (33) and (34) mean that no more than half of the percentage error in the Z_{0T} can appear as the percentage error in the 21G element reach, and the percentage reach error is not larger than the percentage error in the Z_{1T}.

When we consider impedance angle errors, we look at the impedance change due to an angle error:

$$\delta Z_T = 2 \bullet \sin\left(\frac{\Theta_{ERR}}{2}\right) \quad (35)$$

For example, a 5-degree error in Z_{0T} means an error in Z_{0T} of 8.7 percent. Based on (33), the error in the 21G element reach is no greater than 4.4 percent. Because the error angle creates an impedance error that is perpendicular to the impedance vector, (35) is a very conservative approximation and the impact of angle errors in the transformer impedances is much lower.

Overall, the previous error estimation is very conservative. Typically, inaccuracies in the transformer impedance data (±5 percent or ±5 degrees) yield 21G element reach errors of less than 2 percent.

VI. Application Considerations

Perhaps the first application consideration is whether to enable backup protection at all. In a transmission network with redundant primary line protection and local breaker failure, the likelihood of an uncleared fault is very low. However, in a network with lower levels of protection redundancy, backup protection may be justified [11].

For the purpose of this paper, we assume that backup protection is used and we refer to the application guidelines found in [12] and [13]. Both references support two approaches for setting the backup protection: one prioritizes thermal protection for the generator [12] and the other prioritizes backup protection of the transmission system [13]. In this section, we take the latter approach.

A coordination study was conducted for an example system. This study did not consider load encroachment or power swings that may be important considerations for some applications but are not relevant for this paper. The details of the study are included in Appendices C and D and summarized here. In keeping with the theme of the paper, the study focused on the generator 21G element. The following summarizes the outcomes from the study:

- The faulted line up to the remote bus achieved coverage for all fault types.
- Depending on the state of the system, other generators significantly impacted infeed. Zone 3 reach settings were increased to provide coverage.
- A quadrilateral characteristic provided good coverage for resistive ground faults. A memory-polarized mho element could provide similar resistive coverage.
- The 21G element operated faster than the 51N element and, in some cases, significantly faster.
- In some cases, the 51N element operated for faults that the 21G element failed to see, although the 51N element operating times were significantly longer.

VII. Conclusion

This paper introduces a new generator backup distance element that can accurately detect ground faults in the transmission system. A conventional distance element applied at the generator terminals is missing the zero-sequence components needed for accurate ground fault detection. The new approach adds back the zero-sequence components to the currents and voltages prior to processing by the distance function. These measurements are usually available in modern generator relays.

The new 21G element offers some advantages over the traditional 51N element, including a well-defined reach and a fixed operating time. In applications where the generator backup protection is applied as remote backup protection for the transmission line protection, we can set the 21G and 21P elements by using a coordination study.

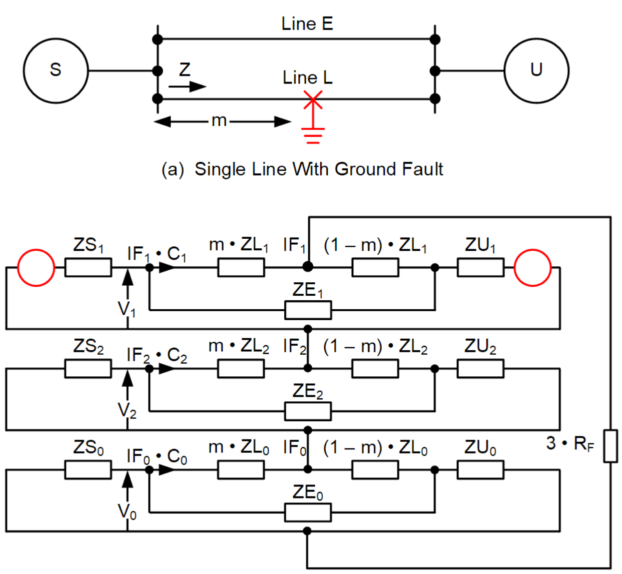
As with other remote backup elements, such as the 21P element and 51N element, infeed negatively impacts the 21G element. Infeed degrades the usefulness of remote backup protection and infeed at a generating plant can be higher than that found in the transmission system. Fault resistance, a consideration for the application of ground fault detection, represents a further challenge to effective backup protection.

The generator 21G element, compared to the 51N element, is faster and better coordinates with the commonly applied transmission line 21G elements. The 51N element, on the other hand, is more sensitive. The generator 21G element can complement the existing generator backup elements in certain power system applications.

VIII. Appendix A

This appendix describes the process for generating the apparent impedance plots of Fig. 4 and Fig. 5. The equations provide a general solution for a double circuit connecting two sources as shown in Fig. 9. In the Section II example, the local source is a generator and a GSU transformer and the remote source is an equivalent power system. We also adopt the following naming conventions:

ZL_{012}	Sequence impedances of the protected (faulted) line
ZE_{012}	Sequence impedances of the parallel (external) line. In the example, the parallel line is out of service.
ZS_{012}	Sequence impedances of the local source. ZS_1 and ZS_2 sum the corresponding sequence impedance of the generator and GSU transformer. ZS_0 is the zero-sequence impedance of the GSU transformer only.
ZF_{012}	Sequence impedances of the fault
ZU_{012}	Sequence impedances of the remote source
C_{012}	Sequence current distribution factors
IF_{012}	Sequence fault currents
V_{012}	Sequence fault voltages at the relay
R_F	Fault resistance
m	Fault location in per unit



(a) Single Line With Ground Fault

(b) Sequence Network for Ground Fault

Fig. 9. Faulted power system with two sources and two lines.

The equations are presented in matrix form. The 012 subscript denotes a column vector of zero-, positive-, and negative-sequence components. Similarly, the pp subscript denotes a column vector of phase-to-phase components. The d_{012} variable holds displacement factors used for conversion of sequence components to abc components, and the a operator is $1\angle 120°$.

$$d_{012} = \begin{bmatrix} 1-a^2 \\ a-1 \\ a^2-a \end{bmatrix} = \begin{bmatrix} \sqrt{3}\angle 30° \\ \sqrt{3}\angle 150° \\ \sqrt{3}\angle 270° \end{bmatrix} \quad (36)$$

$$ZM_{012} = m \cdot ZL_{012} + \frac{ZS_{012} \cdot ZE_{012}}{ZS_{012} + ZE_{012} + ZU_{012}} \quad (37)$$

$$ZN_{012} = (1-m) \cdot ZL_{012} + \frac{ZU_{012} \cdot ZE_{012}}{ZS_{012} + ZE_{012} + ZU_{012}} \quad (38)$$

$$C_{012} = \frac{ZN_{012}}{ZM_{012} + ZN_{012}} \quad (39)$$

$$Z_{012} = ZL_{012} + \frac{ZM_{012} \cdot ZN_{012}}{ZM_{012} + ZN_{012}} \quad (40)$$

$$ZF_{012} = R_F + C_{012} \cdot m \cdot Z_{012} \quad (41)$$

$$ZF_T = ZF_0 + ZF_1 \cdot ZF_2 \quad (42)$$

$$ZC_{012} = Z_{012} - m \cdot ZL_{012} \quad (43)$$

$$V_{pp} = \begin{bmatrix} d_0 \cdot ZF_T + d_0 \cdot ZC_0 - d_2 \cdot ZC_2 \\ d_2 \cdot ZF_T + d_2 \cdot ZC_0 + 2 \cdot d_2 \cdot ZC_2 \\ d_1 \cdot ZF_T + d_1 \cdot ZC_0 - d_2 \cdot ZC_2 \end{bmatrix} \quad (44)$$

$$I_{pp} = \begin{bmatrix} d_0 \cdot C_1 - d_1 \cdot C_2 \\ d_2 \cdot C_1 - d_2 \cdot C_2 \\ d_1 \cdot C_1 - d_0 \cdot C_2 \end{bmatrix} \quad (45)$$

$$Z_{pp} = \frac{V_{pp}}{I_{pp}} \quad (46)$$

IX. Appendix B

Consider a GSU transformer such as that shown in Fig. 10. H and X refer to the wye and delta windings, respectively. This appendix lists all calculations in primary units and expresses the impedance values at the same base as the associated currents.

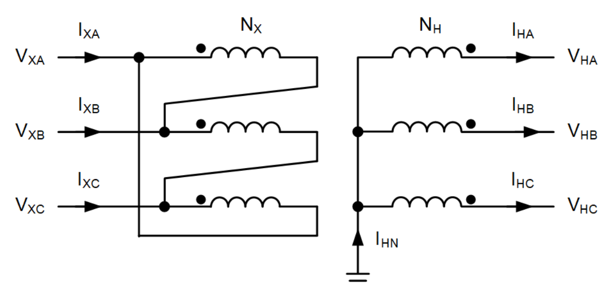


Fig. 10. Sample GSU transformer connection diagram (YNd1), associated variables, and signals.

We use the following variables:

V_H and V_X are the nominal H- and X-side voltages.

N_H and N_X are the turn numbers of the H and X windings.

Z_{1T} and Z_{0T} are the positive- and zero-sequence impedances of the GSU transformer.

V_{Xp} and I_{Xp} are the X-side voltage and current, p-phase, respectively.

V_{Hp} and I_{Hp} are H-side voltage and current, p-phase, respectively.

I_{HN} is the current in the neutral connection.

We assume an ideal transformer (i.e., neglecting the voltage drop across the GSU transformer) and write:

$$\frac{V_{HA}}{V_{XA} - V_{XB}} = \frac{N_H}{N_X} \tag{47}$$

We substitute:

$$\frac{N_H}{N_X} = \frac{K}{\sqrt{3}}, \text{ where } K = \frac{V_H}{V_X} \tag{48}$$

and solve for V_{HA}:

$$V_{HA} = \frac{K}{\sqrt{3}} \bullet \left(V_{XA} - V_{XB}\right) \tag{49}$$

We must further compensate (49) for the zero-sequence voltage drop that is present at the wye side of the GSU transformer. The zero-sequence voltage is the product of the zero-sequence impedance of a transformer and the zero-sequence current in the wye winding (one-third of the current in the neutral connection):

$$V_{HA} = \frac{K}{\sqrt{3}} \bullet \left(V_{XA} - V_{XB}\right) - \frac{1}{3} \bullet I_{HN} \bullet Z_{0T} \tag{50}$$

We can combine the positive- and negative-sequence voltage drops because the transformer positive- and negative-sequence impedance are equal. The voltage drop in the positive- and negative-sequence network is accounted for with the appropriate phase-to-phase current multiplied by the positive-sequence impedance:

$$V_{HA} = \frac{K}{\sqrt{3}} \bullet \left[\left(V_{XA} - V_{XB}\right) - Z_{1T} \bullet \left(I_{XA} - I_{XB}\right)\right] - \frac{1}{3} \bullet I_{HN} \bullet Z_{0T} \tag{51}$$

In (51), the Z_{1T} impedance is on the X base, and the Z_{0T} impedance is on the H base.

Equation (51) applies to the A-phase voltage, and we obtain the B- and C-phase voltages by rotating the indices in (51):

$$V_{HB} = \frac{K}{\sqrt{3}} \bullet \left[\left(V_{XB} - V_{XC}\right) - Z_{1T} \bullet \left(I_{XB} - I_{XC}\right)\right] - \frac{1}{3} \bullet I_{HN} \bullet Z_{0T} \tag{52}$$

$$V_{HC} = \frac{K}{\sqrt{3}} \bullet \left[\left(V_{XC} - V_{XA}\right) - Z_{1T} \bullet \left(I_{XC} - I_{XA}\right)\right] - \frac{1}{3} \bullet I_{HN} \bullet Z_{0T} \tag{53}$$

We use (51), (52), and (53) to calculate the wye-side voltage based on the transformer impedances, the currents and the phase-to-phase voltages on the delta side, and the neutral current on the wye side.

A. Current Transfer

We assume an ideal transformer (i.e., neglecting the magnetizing current) and write the ampere-turn balance equations:

$$\left(I_{HA} - I_{HC}\right) \bullet N_H = I_{XA} \bullet N_X \tag{54}$$

and:

$$\left(I_{HB} - I_{HA}\right) \bullet N_H = I_{XB} \bullet N_X \tag{55}$$

The third ampere-turn balance equation is redundant, and we cannot use it to solve for the wye-side currents. Instead, we write:

$$I_{HN} = I_{HA} + I_{HB} + I_{HC} \tag{56}$$

We write (54), (55), and (56) in a matrix form:

$$\begin{bmatrix} 1 & 0 & -1 \\ -1 & 1 & 0 \\ 1 & 1 & 1 \end{bmatrix} \bullet \begin{bmatrix} I_{HA} \\ I_{HB} \\ I_{HC} \end{bmatrix} = \begin{bmatrix} \frac{\sqrt{3}}{K} \bullet I_{XA} \\ \frac{\sqrt{3}}{K} \bullet I_{XB} \\ I_{HN} \end{bmatrix} \tag{57}$$

and solve for the wye-side currents:

$$\begin{bmatrix} I_{HA} \\ I_{HB} \\ I_{HC} \end{bmatrix} = \frac{1}{3}\begin{bmatrix} 1 & -1 & 1 \\ 1 & 2 & 1 \\ -2 & -1 & 1 \end{bmatrix} \bullet \begin{bmatrix} \frac{\sqrt{3}}{K} \bullet I_{XA} \\ \frac{\sqrt{3}}{K} \bullet I_{XB} \\ I_{HN} \end{bmatrix} \tag{58}$$

Written in a non-matrix form, (58) becomes:

$$I_{HA} = \frac{1}{\sqrt{3} \bullet K} \bullet I_{XA} - \frac{1}{\sqrt{3} \bullet K} \bullet I_{XB} + \frac{1}{3} \bullet I_{HN} \tag{59}$$

$$I_{HB} = \frac{1}{\sqrt{3} \bullet K} \bullet I_{XA} - \frac{2}{\sqrt{3} \bullet K} \bullet I_{XB} + \frac{1}{3} \bullet I_{HN} \tag{60}$$

$$I_{HC} = \frac{-2}{\sqrt{3} \bullet K} \bullet I_{XA} - \frac{1}{\sqrt{3} \bullet K} \bullet I_{XB} + \frac{1}{3} \bullet I_{HN} \tag{61}$$

We use (59), (60), and (61) to calculate the wye-side currents based on the currents on the delta side and the neutral current on the wye side.

In three-phase systems, we expect symmetrical equations that can be obtained from each other by rolling phase indices. Equations (59), (60), and (61) appear asymmetrical, but it is only because of how we derived them. We bring them to their expected symmetrical form by observing that the X currents sum to zero for any system fault, as calculated by (62).

$$I_{XA} + I_{XB} + I_{XC} = 0 \tag{62}$$

By using (62), we can prove that:

$$I_{XA} + 2 \bullet I_{XB} = I_{XB} - I_{XC} \tag{63}$$

$$-2 \bullet I_{XA} - I_{XB} = I_{XC} - I_{XA} \tag{64}$$

Substituting (63) in (60) and (64) in (61), we obtain:

$$I_{HA} = \frac{1}{\sqrt{3} \bullet K} \bullet \left(I_{XA} - I_{XB}\right) + \frac{1}{3} \bullet I_{HN} \quad (65)$$

$$I_{HB} = \frac{1}{\sqrt{3} \bullet K} \bullet \left(I_{XB} - I_{XC}\right) + \frac{1}{3} \bullet I_{HN} \quad (66)$$

$$I_{HC} = \frac{1}{\sqrt{3} \bullet K} \bullet \left(I_{XC} - I_{XA}\right) + \frac{1}{3} \bullet I_{HN} \quad (67)$$

Equations (65), (66), and (67) have the familiar symmetrical form: (66) and (67) can be obtained from (65) by rolling the indices.

1) Moving the Reach to the Delta Side

Voltages [(51), (52), and (53)] and currents [(65), (66), and (67)] are wye-side signals. If we used these signals, the distance element reach would start on the wye side of the GSU transformer. Instead, we bring these signals to the delta side (GSU transformer ratio compensation) and move the reach to start at the delta side, while keeping the signals as accurate replicas of the wye-side signals.

To obtain the compensated relay currents (I) on the delta-side base, we multiply (65), (66), and (67) by the GSU transformer ratio, K, and obtain:

$$I_A = \frac{1}{\sqrt{3}} \bullet \left(I_{XA} - I_{XB}\right) + \frac{K}{3} \bullet I_{HN} \quad (68)$$

$$I_B = \frac{1}{\sqrt{3}} \bullet \left(I_{XB} - I_{XC}\right) + \frac{K}{3} \bullet I_{HN} \quad (69)$$

$$I_C = \frac{1}{\sqrt{3}} \bullet \left(I_{XC} - I_{XA}\right) + \frac{K}{3} \bullet I_{HN} \quad (70)$$

To obtain the compensated relay voltages on the delta-side base, we divide (51), (52), and (53) by the GSU transformer ratio, K, and account for the voltage drop across the positive-sequence impedance of the GSU transformer due to the ground distance element loop current. Using (51), we calculate the compensated V_A voltage:

$$V_A = \frac{1}{\sqrt{3}} \bullet \left[\left(V_{XA} - V_{XB}\right) - Z_{1T} \bullet \left(I_{XA} - I_{XB}\right)\right] - \frac{1}{3 \bullet K} \bullet I_{HN} \bullet Z_{0T} + I_{AG} \bullet Z_{1T} \quad (71)$$

The AG loop relay current, I_{AG}, is:

$$I_{AG} = I_A + k_0 \bullet 3I_0 \quad (72)$$

We use (65), (66), and (67) to calculate:

$$3I_0 = K \bullet I_{HN} \quad (73)$$

We insert (73) and (68) into (72) and obtain the AG loop current as:

$$I_{AG} = \frac{1}{\sqrt{3}} \bullet \left(I_{XA} - I_{XB}\right) + \frac{K}{3} \bullet I_{HN} + k_0 \bullet K \bullet I_{HN} \quad (74)$$

Or after grouping terms:

$$I_{AG} = \frac{1}{\sqrt{3}} \bullet \left(I_{XA} - I_{XB}\right) + K \bullet IHN \bullet \left(k_0 + \frac{1}{3}\right) \quad (75)$$

We can now substitute (75) in (71) and write:

$$V_A = \frac{1}{\sqrt{3}} \bullet \left[\left(V_{XA} - V_{XB}\right) - Z_{1T} \bullet \left(I_{XA} - I_{XB}\right)\right] - \frac{1}{3 \bullet K} \bullet I_{HN} \bullet Z_{0T} + Z_{1T} \bullet \left[\frac{1}{\sqrt{3}} \bullet \left(I_{XA} - I_{XB}\right) + K \bullet I_{HN} \bullet \left(k_0 + \frac{1}{3}\right)\right] \quad (76)$$

We consolidate terms in (77), bring the transformer impedances to the delta-side base, and obtain:

$$V_A = \frac{1}{\sqrt{3}} \bullet \left(V_{XA} - V_{XB}\right) + \frac{1}{3} \bullet K \bullet I_{HN} \bullet \left[Z_{1T@X} \bullet \left(3 \bullet k_0 + 1\right) - Z_{0T@X}\right] \quad (78)$$

We can now remove the @X designation from the transformer impedances and remember that from this point on they are both on the delta-side base. By rotating the indices, we obtain all three voltages from (78):

$$V_A = \frac{1}{\sqrt{3}} \bullet \left(V_{XA} - V_{XB}\right) + \frac{K}{3} \bullet I_{HN} \bullet \left[Z_{1T} \bullet \left(3 \bullet k_0 + 1\right) - Z_{0T}\right] \quad (79)$$

$$V_B = \frac{1}{\sqrt{3}} \bullet \left(V_{XB} - V_{XC}\right) + \frac{K}{3} \bullet I_{HN} \bullet \left[Z_{1T} \bullet \left(3 \bullet k_0 + 1\right) - Z_{0T}\right] \quad (80)$$

$$V_C = \frac{1}{\sqrt{3}} \bullet \left(V_{XC} - V_{XA}\right) + \frac{K}{3} \bullet I_{HN} \bullet \left[Z_{1T} \bullet \left(3 \bullet k_0 + 1\right) - Z_{0T}\right] \quad (81)$$

The compensated ground distance element with the reach starting at the delta winding uses the voltages calculated in (79), (80), and (81) and the currents calculated in (68), (69), and (70). Equations (68), (69), and (70) and (79), (80), and (81) divide by the square root of 3. We can eliminate this division by multiplying both the voltage and currents by the square root of 3.

We also introduce an auxiliary impedance factor:

$$Z_{COMP} = Z_{1T} \bullet \left(3 \bullet k_0 + 1\right) - Z_{0T} \quad (82)$$

and a scaled current:

$$I_{COMP} = \frac{K}{\sqrt{3}} \bullet I_{HN} \quad (83)$$

and obtain the final voltage and current equations:

$$\begin{aligned} V_A &= V_{XA} - V_{XB} + I_{COMP} \bullet Z_{COMP} \\ V_B &= V_{XB} - V_{XC} + I_{COMP} \bullet Z_{COMP} \\ V_C &= V_{XC} - V_{XA} + I_{COMP} \bullet Z_{COMP} \end{aligned} \quad (84)$$

$$
\begin{aligned}
I_A &= I_{XA} - I_{XB} + I_{COMP} \\
I_B &= I_{XB} - I_{XC} + I_{COMP} \\
I_C &= I_{XC} - I_{XA} + I_{COMP}
\end{aligned} \tag{85}
$$

X. Appendix C

A key consideration for the application of a backup element is coordination with primary system protection, allowing the element to provide remote backup in the same way as a typical step-distance backup element [14]. In this appendix, we use the system in the short-circuit program of Fig. 11 [15] to confirm reach accuracy of the new generator backup ground distance element, confirm its proper coordination with different transmission line primary ground distance elements, and provide settings guidelines. We use the same system parameters as the numerical example in Section IV for the transformers (T1 to T4) and lines (L1 and L2). We simulate single-line-to-ground (SLG) faults at F1 (close-in fault), F2 (intermediate L1 fault at either 40 percent or 50 percent), and F3 (remote terminal fault) to illustrate reach accuracy and coordination.

Note that the generators are high impedance grounded, so the concept of an underreaching ground distance Zone 1 (with minimal to no time delay) is not applicable. The settings guidelines provided are consistent with typical values used for the generator phase distance element used to provide remote backup for multiphase faults [12].

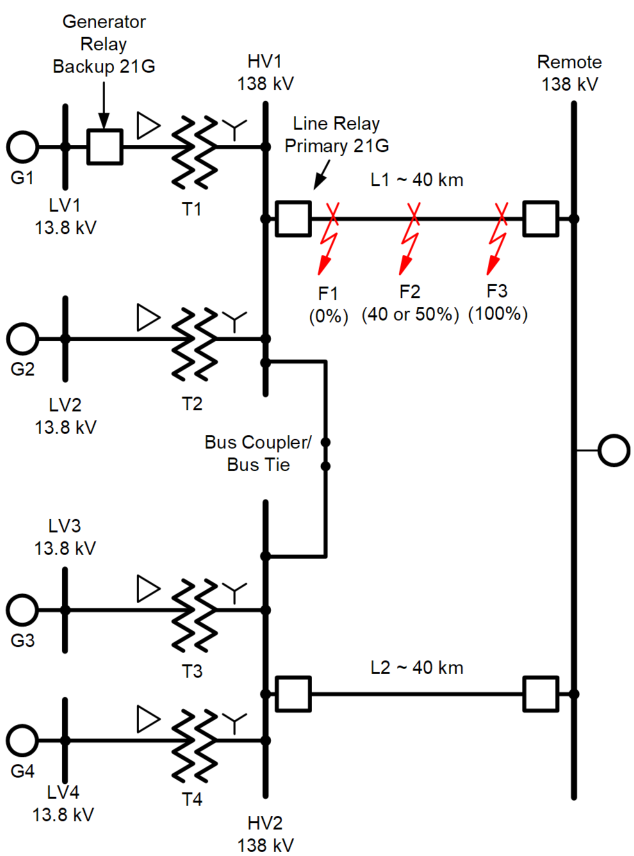


Fig. 11. Short-circuit program system model used to evaluate backup protection performance.

A. Reach Calculation Accuracy

We start with a simple, radial system with Generator G1 and L1 of Fig. 11 in service (i.e., without infeed). The transmission line ground distance element is provided by mho elements, so generator ground mho elements are used to provide backup. The following describes the settings summarized in Table V:

- For dependability, set the Generator Relay Zone 2 reach to greater than $1.2 \bullet Z_{1T}$. For security, Generator Relay Zone 2 coordinates with Line Relay Zone 1 (set to 80 percent of Z_{1L}) with an appropriate margin. Set the Generator Relay Zone 2 to reach as high as 40 percent of Z_{1L}. Additionally, set the Zone 2 characteristic angle, also called the maximum torque angle, based on its reach, i.e., to $\angle(Z_{1T} + 40\% \bullet Z_{1L})$.
- Set the generator ground Zone 2 time delay to allow the primary protection and breaker failure elements to clear the fault.
- Set Generator Relay Zone 3 to provide backup to the Line Relay Zone 2 elements. The reach is set with a dependability margin to $120\% \bullet (Z_{1T} + Z_{1L})$.
- Set the Zone 3 characteristic angle to the angle associated with the fault at the reach, i.e., to $\angle 120\% \bullet (Z_{1T} + Z_{1L})$. The Zone 3 characteristic angle is different from that of Zone 2 to help ensure reach accuracy by accounting for nonhomogeneity between the transformer and line impedances [2]. A generator backup distance zone—either phase or ground—can observe degraded accuracy if the zone's characteristic angle does not correspond to its reach.
- Set the Generator Relay Zone 3 time delay to allow the time-delayed Line Relay Zone 2 and breaker failure elements to clear the fault.
- Set k_0 according to (16). It corresponds to the line Z_0/Z_1 ratio (not using transformer impedances), as stated in Section III.A.
- Supervise the backup zones for a loss-of-potential (LOP) condition. If a generator circuit breaker is installed on the low-voltage side of the GSU transformer, with the VTs measuring generator terminal voltages, the breaker status (e.g., 52a) supervises the element.

Fig. 12 illustrates the performance and coordination from using bolted SLG faults at F1, F2, and F3. The generator and line relays use fault quantities provided by the short-circuit program [15]. Red characteristics represent the primary line relay's distance zones and red x markers represent the measured apparent impedance for faults. Green characteristics represent the backup generator relay's distance zones and green circles represent the measured apparent impedance for faults. For proper comparison, the apparent impedances calculated by the generator relay are scaled by the GSU transformer turns ratio and shifted by Z_{1T} so the origin represents the GSU transformer HV terminals.

The following discusses the key observations and points related to Fig. 12:

- The primary line relay and backup generator relay measure the same apparent impedance for all faults in this system without infeed. This apparent impedance accurately corresponds to the simulated fault location. This demonstrates that the new generator ground distance element is accurate.
- For a close-in fault on L1, Line Relay Zone 1 trips first and Generator Relay Zone 2 provides a backup trip (after 0.5 seconds). Therefore, the backup element is dependable.
- For an intermediate fault (F2) at 50 percent of L1, Line Relay Zone 2 trips first. Generator Relay Zone 2 does not respond to this fault. Generator Relay Zone 3 provides a backup trip (after 1 second). A fault in this region corresponds to the coordination margin, consistent with typical step-distance protection practices [14].
- Generator Relay Zone 3 responds to a remote bus fault and coordinates with Line Relay Zone 2. While not shown in Fig. 12 a remote system fault can be used to verify coordination, showing the region where Generator Relay Zone 3 does not trip and Line Relay Zone 2 trips.

TABLE V
GENERATOR BACKUP GROUND MHO SETTINGS FOR A SYSTEM WITHOUT INFEED

Setting	Value
Zone 2 Reach and Characteristic Angle	19.25 Ω ∠83.7°
Zone 2 Time Delay	0.5 s
Zone 3 Reach and Characteristic Angle	31.99 Ω ∠80.3°
Zone 3 Time Delay	1 s
k_0 Magnitude and Angle	0.67∠12°
Zone 2 and Zone 3 Supervision	52A & NOT LOP

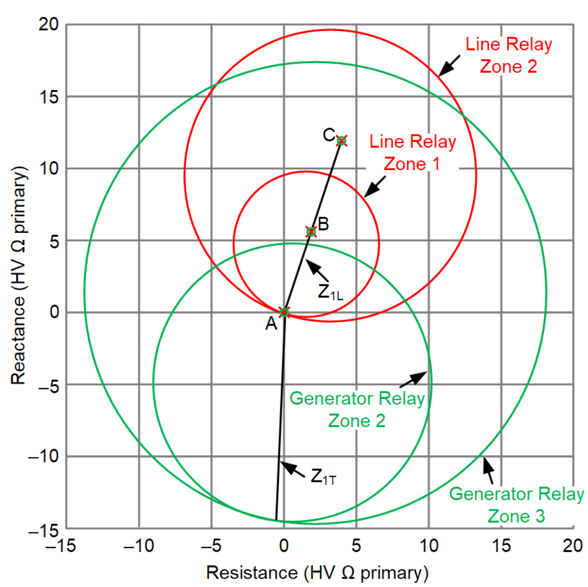


Fig. 12. Accuracy and coordination of generator backup ground mho element shown using bolted faults.

B. Performance for Resistive Faults

The generator phase distance backup is often applied using a mho element because multiphase faults with significant resistance, although uncommon, are possible, especially when the fault remains uncleared for some time [16]. On the other hand, the ground distance element can be required to operate for faults with significant resistances—for which the quadrilateral element can be helpful, especially in short line applications. Also, memory-polarized mho characteristics expand to provide improved coverage for resistive faults.

The settings guidelines for the generator backup ground quadrilateral element are consistent with the principles of step-distance coordination as applied for transmission line protection [1] [14]. In addition to the guidelines from Appendix C.A, observe the following guidelines for the ground mho element:

- Configure the generator relay to use the same polarizing current as the line relay. This example uses loop currents for polarization. We similarly verified performance and coordination of the quadrilateral elements by using I2 and I0 polarization to confirm the accuracy of (6).
- Set the tilt angle for Generator Relay Zone 2 reactance element equal to Line Relay Zone 1. Similarly, set the tilt angle for Generator Relay Zone 3 reactance element equal to Line Relay Zone 2. Use the short-circuit program to tune the tilt setting based on system nonhomogeneity and load flow.
- Set the resistive reach of the backup zones lower than the primary zones without infeed for this application to maintain coordination for highly resistive faults.

Coordination is verified using resistive SLG faults at F1 (for Generator Relay Zone 2) and F3 (for Generator Relay Zone 3), as shown in Fig. 11. The following discusses the key observations and points related to Fig. 13:

- The primary line relay and backup generator relay measure the same apparent impedance for all faults in this system without infeed. The apparent impedance accurately corresponds to the simulated fault location and fault resistance—the fault resistance is divided by $1 + k_0$ in the apparent impedance plane [16]. This illustrates that the generator ground distance element is accurate.
- For a 30-ohm fault at F1 (Point A), Line Relay Zone 1 trips first and Generator Relay Zone 2 provides a backup trip (in 0.5 seconds). Similarly, for a 25-ohm fault at F3 (Point B), Line Relay Zone 2 trips first and Generator Relay Zone 3 provides a backup trip (in 1 second). The backup zones are dependable.
- For a 60-ohm fault at F1 (Point C), Line Relay Zone 1 trips first and Generator Relay Zone 2 does not. Similarly, for a 50-ohm fault at F3 (Point D), Line Relay Zone 2 trips first and Generator Relay Zone 3 does not. These faults verify resistive reach coordination to confirm that the backup zones are secure [16].

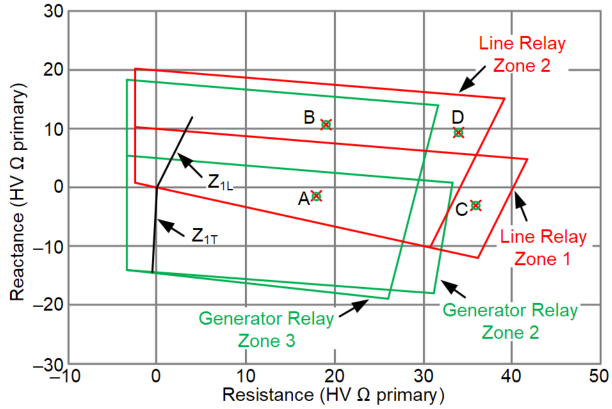


Fig. 13. Accuracy and coordination of generator backup ground quadrilateral element shown using resistive faults.

C. *Infeed*

So far, the examples discussed in this section did not include infeed. In transmission networks, many substations are terminals for more than one generating plant and one transmission line. Infeed from other generators or lines can cause a phase or ground backup distance relay to underreach compared to a primary distance relay. Ground distance backup can further underreach due to the zero-sequence paths presented by other GSU transformers and other network transformers.

The short-circuit program simulates the system with infeed in Fig. 11 [15]. Contingencies are considered but their philosophy can vary amongst utilities. The following discusses the backup ground quadrilateral element settings, as summarized in Table VI. A similar approach is applicable to the mho element:

- Set Generator Relay Zone 2 with an emphasis on security. This zone coordinates with Zone 1 and breaker failure protection for all lines. In our system, both L1 and L2 have the same impedance. However, due to the topology, the smallest apparent impedance is measured for a fault on L1 with the bus coupler/bus tie open (thus removing the highest infeed). This apparent impedance includes infeed (from Generator G2) and is used to set the Zone 2 reactive reach and characteristic angle. The apparent impedances measured by the line and generator relays (Points A and B in Fig. 13, respectively) illustrate the effect of infeed for an F2 fault at 40 percent from HV1 terminal.
- Set Generator Relay Zone 3 to be dependable for bolted line-end faults at F3 (remote terminal open) with maximum infeed, so the relay measures the highest apparent impedance (Point D). The remote line protection may likely operate correctly whereas the local line protection may fail to clear the fault, thereby requiring backup from the generator backup distance zones. Set the Zone 3 reactive reach to 1.2 times the apparent impedance associated with Point D. As with typical practices, we can use the short-circuit program to check if Generator Relay Zone 3 overreaches additional line relay zones (e.g., Zone 3) after removing infeed for contingencies and, if an overreach occurs, adjust zone reach or increase the time delay for proper coordination. In this application, we assume that Generator Relay Zone 3 coordinates with all Line Relay Zone 3 elements for all credible contingencies.
- Set Generator Relay Zone 2 resistive reach by considering the impact of infeed on the apparent impedance measured for a resistive fault by using (86) [16]. To obtain a secure setting, use a fault simulation with the bus coupler and remote terminal open.

$$R_{GEN\_BKP} \le k \bullet \left| \frac{Zapp_{BKP} - Z_{1T}}{Zapp_{PRI}} \right| \bullet R_{LINE\_PRI} \quad (86)$$

where:

R_{LINE_PRI} is the resistive reach of the line relay.

R_{GEN_BKP} is the resistive reach of the generator relay.

$Zapp_{BKP}$ is the apparent impedance calculated by the backup generator relay for the fault.

$Zapp_{PRI}$ is the apparent impedance calculated by the primary line relay for the fault.

k is a security margin.

Z_{1T} is the positive-sequence impedance of the GSU transformer.

- Simulate a close-in fault just within the Zone 2 resistive reach (60-ohm fault) to obtain the values used by (86). Set the Generator Relay Zone 2 resistive reach to less than 68.2 ohms, as shown in (87), to coordinate with the Line Relay Zone 1 resistive reach of 40.15 ohms, which uses a security margin of 0.85. The infeed desensitizes the backup relay by a factor of two (Point F with respect to Point E). This corresponds to the contribution from Generator G2, which has the same parameters as Generator G1.

$$R_{GEN\_Z2} \le 0.85 \bullet \left| \frac{72.82\ \Omega\angle 6.4° - 14.38\ \Omega\angle 87.9°}{36.1\ \Omega\angle -4.8°} \right| \bullet 40.15\ \Omega \quad (87)$$

$$R_{GEN\_Z2} \le 68.2\ \Omega\ (28.2) \quad (88)$$

- Use the same secure infeed factor to set the Generator Relay Zone 3 resistive reach less than 88.6 ohms to coordinate with the Line Relay Zone 2 resistive reach of 52.2 ohms. For a resistive fault at F1 with the remote terminal out of service, Point H in Fig. 14 shows Generator Relay Zone 3 dropping out while Line Relay Zone 2 (Point G) remains picked up. Similarly, Points I and J illustrate coordination for a resistive fault at F3.

In some applications, tripping the bus coupler within the Generator Relay Zone 2 time delay for a nearby fault is normal (and not a contingency). For example, tripping the bus coupler for an uncleared HV1 bus fault can help prevent a time-out of a step-distance zone applied at the remote bus of L2. This leaves L2 in service, allowing Generators G3 and G4 to remain online and support the system. In such applications, it may be the case that a single contingency corresponds to an outage of Generator G2, disconnection of all infeed, and similar settings as those included in Appendix C.A and C.B.

Fig. 14 illustrates coordination for self-polarized quadrilateral zones, as in Appendix C.B We similarly confirmed coordination for quadrilateral elements polarized by I2 or I0.

TABLE VI
GENERATOR BACKUP GROUND QUADRILATERAL SETTINGS FOR SYSTEM WITH INFEED

Setting	**Value**
Zone 2 Reach and Characteristic Angle	24.17 Ω ∠81.2°
Zone 2 Resistive Reach	68.2 Ω
Zone 2 Time Delay	0.5 s
Zone 3 Reach and Characteristic Angle	81.53 Ω ∠59.8°
Zone 3 Resistive Reach	88.6 Ω
Zone 3 Time Delay	1 s

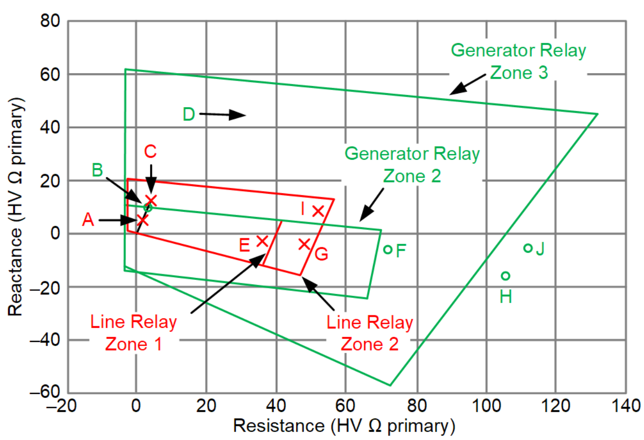


Fig. 14. Coordination of ground quadrilateral zones in a system with infeed.

If the GSU transformer has a tap changer, we can adjust the reactive and resistive reaches accordingly.

XI. APPENDIX D

In this appendix, we compare the performance of the new generator ground distance element with the ground time-overcurrent element that typically provides ground-fault backup protection. The performance is compared using a short-circuit program [15] by simulating ground faults at F1 and F3, as shown in Fig. 7.

The 51N element uses the neutral-current input of the GSU transformer, as shown in Fig. 1. Its pickup setting is selected at 200 primary amperes. Select an inverse curve (ANSI U2) and time dial of 5 for this backup element to coordinate with the primary system ground fault protection. Set the 21G backup element by using ground quadrilateral zones according to Appendix C.C. The 51N and the 21G elements use different operating signals, so their operating times are used for performance comparison. Table VII shows the operating times (in seconds) of the two elements for different scenarios. From the table, we observe that the following:

- The new 21G backup element operates faster than the 51N element and exhibits a consistent operating time, regardless of the system configuration.
- The 21G backup element can operate much faster than the 51N element for faults with low resistance and, when using a quadrilateral characteristic, moderate resistance.
- The 51N element can detect higher-resistance faults than the 21G element.

These observations are consistent with what we know and expect from the 21G and 51N elements used in line protection applications. The 21G element also has additional VT requirements, unlike the 51N element. The new 21G element complements the 51N element quite well for backup protection in this application.

TABLE VII
RELAY OPERATING TIMES (IN SECONDS) FOR SLG FAULTS

Case	**Description**	**51N**	**21G**
1	F1	1.038	0.5
2	F3 with remote terminal closed	1.803	1.0
3	F3 with remote terminal open	3.346	1.0
4	Case 1 with either G2, G3, or G4 out	1.038	0.5
5	Case 2 with either G2, G3, or G4 out	1.544	1.0
6	Case 3 with either G2, G3, or G4 out	2.462	1.0
7	Case 1 with L2 out	1.038	0.5
8	Case 2 with L2 out	3.347	1.0
9	Case 3 with L2 out	3.347	1.0
10	Case 1 with 25-ohm fault resistance	3.068	0.5
11	Case 2 with 25-ohm fault resistance	4.402	1.0
12	Case 3 with 25-ohm fault resistance	6.734	1.0
13	Case 1 with 60-ohm fault resistance	18.16	NA
14	Case 2 with 60-ohm fault resistance	22.69	NA
15	Case 3 with 60-ohm fault resistance	NA	NA

XII. ACKNOWLEDGEMENT

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XIV. Biographies

Dale Finney received his BS degree in engineering from Lakehead University, and his master of engineering degree from the University of Toronto, Canada. He began his career with Ontario Hydro, where he worked as a protection and control engineer. Currently, he is employed as a principal power engineer with Schweitzer Engineering Laboratories, Inc . He holds more than a dozen patents and has authored more than 30 papers in the area of power system protection. He is a member of the main committee and past chair of the rotating machinery subcommittee of the IEEE PSRC committee. He is a senior member of the IEEE and a registered professional engineer in the province of Nova Scotia.

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