Distance Protection in Distribution Systems: How It Assists With Integrating Distributed Resources

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***Abstract*—The integration of distributed generation (DG) or distributed resources in the distribution system poses technical constraints for the electrical power system owner or manager. The addition of relatively large amounts of generation to the distribution system can potentially challenge the historical setting principles and design assumptions made in developing protection and control strategies based on overcurrent protection. The necessity and complexity of additional protection and control measures increase as the aggregate DG capacity within a potential island approaches or offsets the load within that island. In addition, the varying nature of DG availability and fault current capability must also be considered. The key issues discussed and associated with DG on the distribution feeder include anti-islanding, temporary overvoltages during fault conditions, and loss of sensitivity of feeder overcurrent protection for long feeders. As the distribution system evolves to accommodate more DG, the design and implementation of the feeder protection must also evolve. This paper presents the use of distance relays for distribution protection to solve some of the DG integration problems. This paper provides real-world event report data to further demonstrate the performance of distance protection on the distribution system. A relative cost comparison between various feeder protection solutions is presented along with a discussion on options for education of distribution companies challenged with implementing distance protection for the first time.**

***Index Terms*—Distance protection, distributed generation (DG), distribution protection.**

I. Introduction

A DISTRIBUTION feeder often consists of a main trunk with lateral circuits emanating along its length (Fig. 1).

These laterals typically are connected to the main trunk through a fuse. Feeder protection is designed to ensure that a permanent fault on a fused lateral will only result in an outage for that lateral (Fig. 2). For longer feeders with midline reclosers, the feeder protection is set to prevent tripping of the source breaker for faults downstream of the recloser.

Historically, overcurrent protection has been used on the distribution system for instantaneous and timed tripping of the feeder breaker. It is estimated that 80%–90% of distribution faults are temporary. As a consequence, utilities often use autoreclosing to minimize customer sustained interruptions.

Two strategies are employed in the application of fuses in distribution networks: fuse-saving and trip-saving schemes. A fuse-saving scheme opens an upstream breaker or recloser before the fuse begins to melt and is followed by an autoreclose of the circuit. If the fault is temporary, then the fuse is saved. In a trip-saving scheme, the fuse is allowed to blow for all faults. A fuse-saving scheme produces more momentary interruptions but fewer sustained interruptions compared with trip saving. In either application, the goal is to clear transient faults while limiting the number of customers affected by faults on fused laterals. Many utilities combine these two strategies.

In a fuse-saving scheme, an instantaneous protection element trips the feeder breaker for all downstream faults in an attempt to clear the fault. The breaker is tripped before the downstream lateral fuses begin to melt. Following the initial trip, the

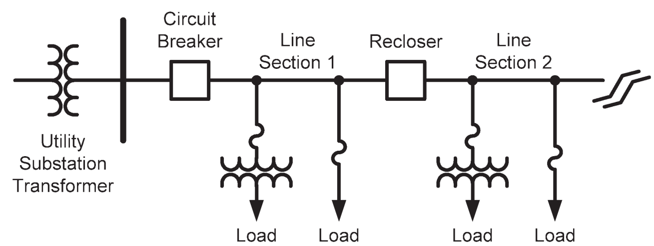

Fig. 1. Typical distribution feeder.

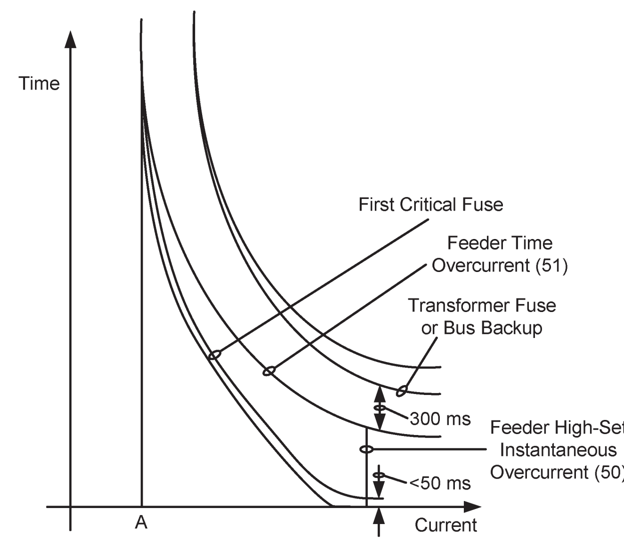

Fig. 2. Typical coordination curves for a distribution feeder.

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instantaneous protection elements are blocked temporarily. After a sufficient time delay, the breaker is reclosed. The reclose time is set such that there is sufficient time for the ionized air at the place of the fault to dissipate and be replaced by cold nonionized air and for all thermal and electrical protection elements to reset (or return to the reset position). In the event that the remote fault is permanent, the time-delayed protection operates while coordinating with any protection on the supply side of the feeder breaker (such as transformer, bus, or high-voltage line), as well as the fuses located on the single-phase, two-phase, or three-phase taps off the main feeder. For faults close to the feeder breaker, an instantaneous high-set protection element is provided to rapidly isolate close-in faults to minimize cumulative damage or loss of life to the source transformers.

The addition of generation into distribution systems can result in increased requirements for the feeder protection scheme. Features such as directional elements and load encroachment can be used to improve the sensitivity and security of overcurrent-based feeder protection schemes. With the addition of midline reclosers, fast discrimination between in-zone and out-of-zone faults is a necessity to retain protection selectivity. For these situations, protective relays equipped with distance elements can provide a more reliable and secure protection scheme. Distance elements are impedance based and provide a fixed reach, whereas overcurrent elements have a reach that varies with changes in the upstream source impedances and/or system configuration. Distance elements are inherently directional and provide better discrimination between remote-end in-zone and out-of-zone faults.

II. Current-Based Protection for Feeders Without DG

A. Time-Overcurrent Protection

The traditional setting criterion for overcurrent feeder protection without load encroachment is based on the ratio of minimum fault current to maximum load current. It is essential that protective relays respond to end-of-section faults. One criterion for setting the timed pickup (PU) threshold is to divide the minimum three-phase fault current (I3MinF) for a fault at the end of the feeder by three. This is a common utility practice that provides a margin for fault resistance coverage. The impedance to fault coverage will be 300% of the total positive-sequence impedance for three-phase faults. The fault current for a solid phase-to-phase fault is 86.6% of a three-phase fault [1]. The coverage will be 86.6% of 300% or 260% for a phase-to-phase fault. Load current is typically not a concern, and in most applications, the pickup current is easily 30% greater than the maximum load current (IMaxL). For longer feeders, dividing the three-phase end-of-feeder fault current by three may result in a pickup setting that is equal to or lower than the maximum load current of the feeder. It is important to verify that the minimum pickup setting is at least 30% greater than the maximum load current to ensure that there is no risk of a false operation due to load. Some utilities, such as Hydro One Networks, Inc., prefer to maintain this 4 : 1 fault-to-load ratio

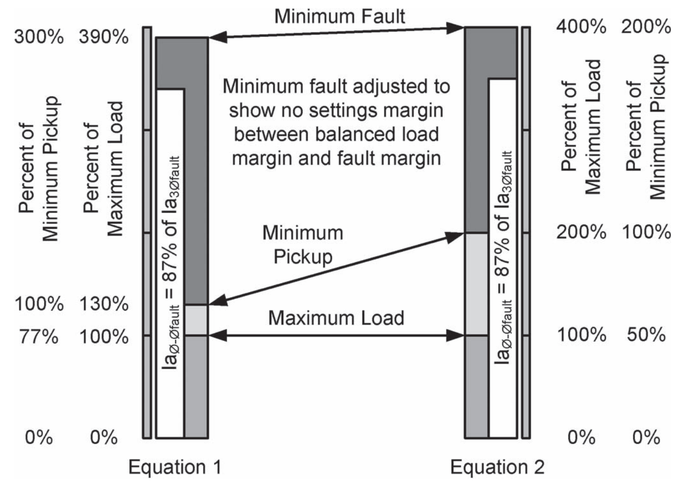

Fig. 3. Phase overcurrent setting criteria.

with a minimum pickup, typically twice the maximum load current

$$\frac{\text{I3MinF}}{3} > \text{51PPU} > 1.3 \bullet \text{IMaxL}. \tag{1}$$

Alternatively,

$$\frac{\text{I3MinF}}{2} > \text{51PPU} > 2 \bullet \text{IMaxL}. \tag{2}$$

Fig. 3 graphically demonstrates the phase overcurrent minimum fault to minimum pickup and minimum pickup to maximum load margins provided by (1) and (2).

This same philosophy can be used for ground overcurrent protection; the pickup is calculated by dividing the fault current for a solid single-line-to-ground fault at the end of the feeder (3I0MinF) by three. The resulting impedance fault coverage is approximately three times the total positive-sequence impedance to the fault with zero-sequence compensation. Balanced load current is not a concern for ground current protection, but unbalanced load must be taken into consideration. One philosophy is to select the pickup to be greater than 20% of the maximum load current (IMaxL). Using 20% of maximum or nominal load current is acceptable for systems where the load unbalance is no more than 10%–15%. For systems where the load unbalance is known to be larger, the pickup is set above the maximum load unbalance (3I0MaxL) with margin

$$\frac{\text{3I0MinF}}{3} > \text{51NPU} > 0.2 \bullet \text{IMaxL}. \tag{3}$$

Alternatively,

$$\frac{\text{3I0MinF}}{2} > \text{51NPU} > 2 \bullet \text{3I0MaxL}. \tag{4}$$

Fig. 4 graphically demonstrates the ground overcurrent minimum fault to minimum pickup and minimum pickup to maximum load unbalance margins provided by (3) and (4).

Feeder overcurrent protection is designed to accommodate the topology of the distribution system. Systems with longer lines require increased sensitivity for the pickup setting value due to the lower remote-end fault current. Therefore, the longer

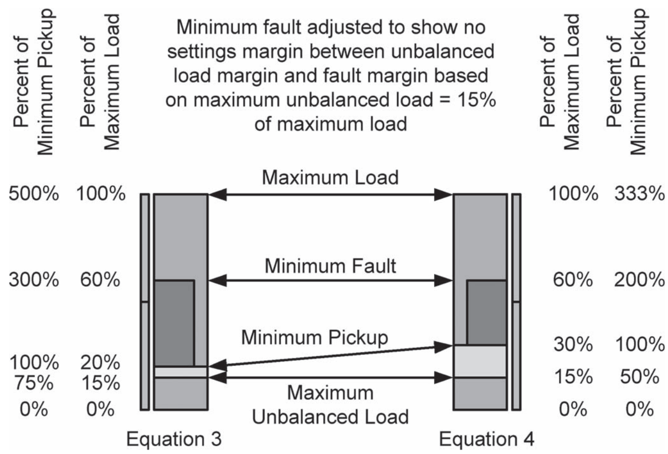

Fig. 4. Ground overcurrent setting criteria.

the line, the greater the impact load will have on the pickup setting value, dividing the minimum fault value by two rather than three and increasing the load margin trade fault margin for load margin. If a 4 : 1 fault-to-load trip ratio cannot be maintained, then other alternatives are deployed, such as phase mho torque-controlled 51P or load encroachment.

Both phase and ground coordination must be verified against both upstream and downstream devices to ensure correct coordination.

Curve selection is based on the upstream and downstream protection devices, such as transformer or bus backup protection and fusing for tapped loads. Typically, the time dial (TD) is selected to provide a 300-ms coordination margin at maximum fault levels. This 300-ms margin allows protection engineers or technicians to select TD settings without the complete details regarding the time-current curve accuracy of all connected protection devices. Today, with the more consistent operating times provided in microprocessor-based devices, this margin can safely be decreased.

B. Instantaneous Overcurrent Protection

It is a common practice to use both instantaneous and timed tripping on distribution feeders in combination with autoreclosing. High-set instantaneous settings are often employed to limit damage and reduce loss of life to utility transformers due to close-in permanent faults. Another application for instantaneous elements is a fuse-saving scheme where low-set instantaneous elements are used.

High-set instantaneous phase overcurrent (50 H) and high-set instantaneous ground overcurrent (50 NH) elements are set to coordinate with the first critical tapped primary fuse on the feeder. The high-set phase and ground instantaneous elements should not operate for feeder energization or cold load inrush, and thus, the pickup is typically four to six times the maximum load (IMaxL and 3I0MaxL). This margin of four times the maximum load must also be compared to maximum inrush to confirm a sufficient margin. The high-set instantaneous pickup is selected to provide maximum feeder coverage and minimize transformer high through-fault current that would otherwise be cleared by slower time-overcurrent protection. One method is to select the high-set phase with a pickup of less than one-half of the minimum three-phase bus fault (I3MinBF) and to confirm that this pickup is also 25%–33% larger than the maximum three-phase fault at the first critical primary fuse (I3MaxFFuse). This setting of 1.25–1.33 times the fault current at this first critical primary fuse is equal to the current obtained for a short circuit at 80%–75%, respectively, of the distance to this first critical primary fuse. Instantaneous devices cannot be coordinated with downstream devices, so the setting of the high-set instantaneous protection is selected to avoid operation for faults beyond the first critical tapped primary fuse. The high-set ground overcurrent protection is coordinated with the maximum single-line-to-ground fault at the first critical primary fuse (3I0MaxFFuse). The setting for the high-set instantaneous ground protection is less than one-half of the minimum single-phase-to-ground bus fault (3I0MinBF) and 25%–33% larger than 3I0MaxFFuse

$$\frac{\text{I3MinBF}}{2} > 50\text{ H} > 1.33 \bullet \text{I3MaxFFuse} \tag{5}$$

$$50\text{ H} > 4 \bullet \text{IMaxL} \tag{6}$$

$$\frac{\text{3I0MinBF}}{2} > 50\text{ NH} > 1.33 \bullet \text{3I0MaxFFuse} \tag{7}$$

$$50\text{ NH} > 4 \bullet \text{3I0MaxL}. \tag{8}$$

The tripping logic for phase protection can include a selection of at least two phase elements. The logic is such that two out of three phases must operate to allow phase tripping. This logic is applied to ensure phase coordination with phase curves and ground coordination with ground curves to account for a situation where phase and ground coordination curves and settings differ. The logic also aids in postfault analysis. Thus, the phase instantaneous element does not trip the feeder for single-line-to-ground faults.

Sensitive low-set instantaneous overcurrent elements are used in fuse-saving schemes. These overcurrent elements are set to cover the entire feeder main trunk and laterals. The general philosophy is that transient faults can be cleared with a single feeder breaker trip and subsequent autoreclosing, resulting in no need for lateral fuse replacement. This philosophy is mostly seen within utilities having long rural feeders where temporary faults are common and the distance traveled with corresponding time to replace a fuse can be substantial. The sensitive elements are blocked following the initial reclose. Should the breaker reclose into a fault, the time-overcurrent elements provide timed coordination protection with the downstream devices.

The sensitive phase instantaneous (50 L) elements and the sensitive ground instantaneous (50 NL) elements are set following similar guidelines as the pickup for the phase and ground time-overcurrent elements

$$\frac{\text{I3MinF}}{2} > 50\text{ L} > 2 \bullet \text{IMaxL} \tag{9}$$

$$\frac{\text{3I0MinF}}{2} > 50\text{ NL} > 2 \bullet \text{3I0MaxL}. \tag{10}$$

Sensitive instantaneous elements are not coordinated to allow for feeder energization, and therefore, these elements are blocked momentarily after the breaker closes to prevent unwanted tripping. These sensitive instantaneous elements can detect faults on adjacent feeders. In four-wire distribution systems, a phase-to-ground fault on an adjacent feeder results in a transient zero-sequence current in the unfaulted feeder due to single-phase loads. Low-set instantaneous elements on adjacent unfaulted feeders can be susceptible to misoperation due to large unbalanced conditions during faults, and directional overcurrent protection on these feeders may be necessary. The addition of distributed generation (DG) may contribute a significant fault current for faults on adjacent feeders. Directional overcurrent elements may be necessary to block tripping from DG infeed during adjacent feeder fault conditions. Directional overcurrent elements provide directional discrimination but may still be susceptible to operation for forward out-of-zone faults, such as on the low-voltage side of tapped load stations. One alternative is to move to distance-based feeder protection schemes.

III. Distance-Based Feeder Protection

Advantages are evident when comparing distance-based feeder protection with overcurrent feeder protection in that it is inherently directional with a fixed reach and easily adaptable on feeders where large amounts of DG are installed. Distance-based feeder protection schemes accommodate instantaneous trip elements and have fixed zones of protection, independent of changing system conditions.

For example, should the source behind the relay change, then fault currents at any location on the feeder will change as a result. However, the impedance of the protected feeder does not change because the ratio of the voltage to the current remains constant, and as such, the distance element is unaffected.

The characteristic of a distance element can be shaped to improve coverage for resistive faults, or it can be secured to prevent operation during a heavy loading condition by using load encroachment. Distance elements derive their operating and polarizing signals from measured voltages and currents. These signals are applied either to a magnitude or angle comparator from which a trip decision is derived. The selection of the operating and polarizing quantities determines the shape of the distance (impedance) element. For example, choosing (IZ-V) as the operating signal and V as the polarizing signal and applying these to an angle comparator in (11) produce the operating characteristic shown in Fig. 5

$$\text{angle}\left(\frac{(\text{IZ}-\text{V})}{V}\right) < |90^\circ|. \tag{11}$$

Under unfaulted system conditions, the measured impedance ($Z = Z_{\text{LOAD}}$) is the impedance of the load supplied by the feeder (the feeder impedance is also considered part of the load). The load impedance is typically near the real axis (R) of the impedance plane (load on the feeder typically has a power factor $\cong 1$ compensated by capacitor banks, as required for the inductive component of the feeder or for inductive loads). When a fault occurs, the measured impedance changes from load impedance (mostly resistive) to an impedance with

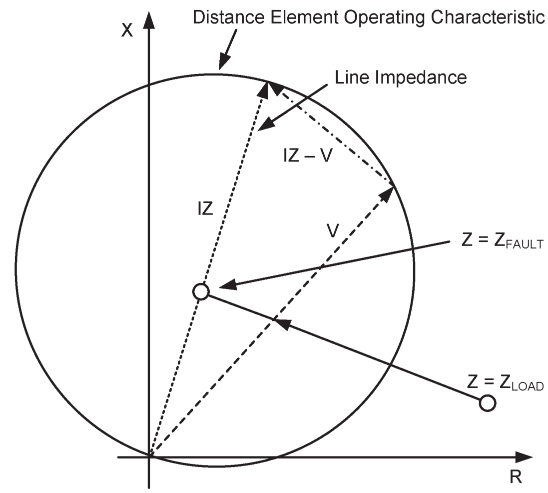

Fig. 5. Mho impedance characteristic.

a much larger inductive component, which is primarily determined by the impedance of the feeder (if high-resistance arcing faults are neglected). The complete distance zone has six loops, with each loop measuring positive-sequence impedance by responding to correctly selected combinations of voltage and current, with the AB loop (no fault resistance) referenced in (12).

Equation (12) provides the positive-sequence line impedance of the faulted line section

$$V = \text{VA} - \text{VB} \quad I = \text{IA} - \text{IB} \quad Z = V/I = m\text{Z1L} \tag{12}$$

where

Z1L positive-sequence line impedance;

m distance to the fault in per unit of Z1L [2].

The distance-based feeder protection discussed in this paper is a combination of traditional overcurrent protection coordination and distance elements. Both mho and quadrilateral elements are applied in this implementation of distance-based feeder protection. For details on both mho and quadrilateral distance elements and for direction to further references, see [1]–[6].

IV. Current Infeed Due to DG

The addition of generation has a significant impact on feeder protection. Considering the case of a line-end three-phase fault for the circuit shown in Fig. 6, we can calculate the fault current at the feeder end with no generation as follows:

$$\text{IF}_{\text{NDG}} = \frac{V_{\text{SYS}}}{Z_{\text{SYS}} + Z_S + Z_H} \tag{13}$$

where

Z_{SYS} impedance of the utility source;

Z_S impedance from the substation to the generator;

Z_H impedance from the generator to the line end;

V_{SYS} voltage behind the source impedance.

When we add the generator and neglect the load, the total fault current is the following:

$$\text{IF}_{\text{DG}} = \frac{V_{\text{SYS}}}{Z_H + \frac{Z_{\text{DG}}\bullet(Z_{\text{SYS}}+Z_S)}{Z_{\text{DG}}+Z_{\text{SYS}}+Z_S}} \tag{14}$$

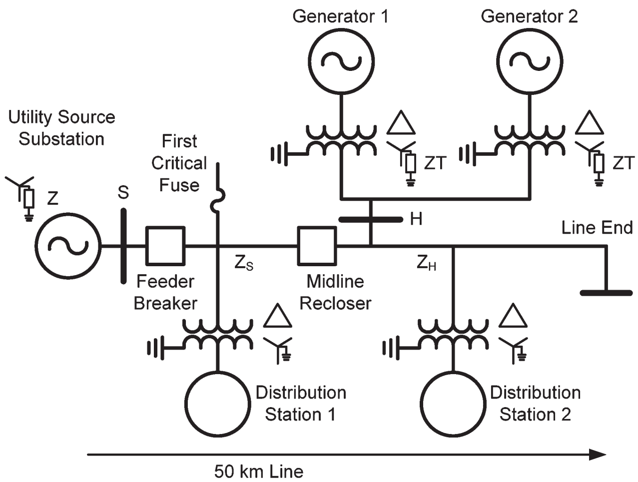

Fig. 6. Distribution feeder with connected generation.

where

Z_{DG} combined impedance of the generator and step-up transformer;

Z_{SYS} impedance of the utility source.

The fault current contribution from the utility source is now the following:

$$I_S = \mathrm{IF}_{\mathrm{DG}} \bullet \frac{Z_{\mathrm{DG}}}{Z_{\mathrm{DG}} + Z_{\mathrm{SYS}} + Z_S}. \tag{15}$$

The fault current contribution from the DG is the following:

$$I_H = \mathrm{IF}_{\mathrm{DG}} \bullet \frac{(Z_{\mathrm{SYS}} + Z_S)}{Z_{\mathrm{DG}} + Z_{\mathrm{SYS}} + Z_S}. \tag{16}$$

If we calculate the fault current contribution from the utility source of Fig. 1 for arbitrary values of Z_S, Z_H, and Z_{DG}, we find that the addition of local generation always reduces the fault current contribution from the substation. Depending on the size and location of the generator, the overcurrent protection located at the substation may need to be set very sensitive due to the Z_{DG} impact of the generator relative to $Z_{\mathrm{SYS}} + Z_S$ and still be able to detect faults at the end of the line, including both solid and resistive faults.

Ground overcurrent protection can be set to be more sensitive than phase overcurrent protection because it does not measure balanced load. However, the available ground fault current at the substation is further affected by the method of grounding at the generator transformer. The optimal grounding method is always a tradeoff between fault current contribution and acceptable overvoltages. The type of grounding at the generator facility must be compatible with the system to which it will be connected. For this reason, the grounding on the generator step-up transformer at the utility interconnection is usually mandated by the utility. Effective grounding is often chosen for four-wire networks in order to limit temporary overvoltages to a safe value to protect single-phase loads and surge arrestors. The zero-sequence impedance of an effectively grounded system is less than or equal to three times the positive-sequence impedance ($X_0 \leq 3 \bullet X_1$ and $R_0/X_1 \leq 1$). A solidly grounded connection at the generator transformer is often avoided because, although it successfully limits ground fault temporary overvoltages, it also produces excessive ground fault current and therefore reduces the utility-supplied ground fault current, effectively desensitizing the feeder protection. Unbalanced load conditions present on four-wire feeders limit the sensitivity of ground fault protection, and thus, neutral grounding reactors on the primary side of the generator step-up transformer are sized to maintain an effectively grounded system yet still provide the utility with the ground fault current required for coordination. The secondary or tertiary winding of the generator step-up transformer must also allow the flow of zero-sequence currents. In three-wire networks, loads are connected phase to phase. The load transformer primary windings are typically wye ungrounded or delta. Sensitive ground fault protection can be applied under these circumstances if the generator step-up transformers tapped to three-wire networks also adopt the same primary connection as load transformers.

Distance protection is also impacted by local generation. The apparent feeder impedance is the impedance measured by the distance relay. On a feeder with a single source of fault current, the apparent impedance will agree closely with the actual impedance between the relay location and the fault point. With the addition of generation, this situation changes. The relay at the utility source substation sees only I_S and V_S. V_S is the voltage drop for this feeder-end fault and is shown in the following:

$$V_S = I_S \bullet Z_S + (I_S + I_H) \bullet Z_H. \tag{17}$$

This results in an apparent impedance of the following:

$$Z_{S\_\mathrm{APP}} = Z_S + Z_H + \frac{I_H}{I_S} \bullet Z_H = Z_S + \frac{I_S + I_H}{I_S} \bullet Z_H. \tag{18}$$

This Z_{S_APP} compares to the actual impedance of the fault

$$Z_{S\_\mathrm{ACT}} = Z_S + Z_H. \tag{19}$$

It can be seen that Z_{S_APP} increases by $(I_H/I_S) \bullet Z_H$. When DG is added to the distribution feeder, the fault current from the generation adds to the fault current from the utility such that, for a feeder-end fault, the impedance measured is larger than the actual impedance. The greater the MVA rating of the generator, the greater the magnitude of I_H, and the greater the increase in impedance. This successfully decreases the effective reach of the distance element.

This apparent effect is also seen in ground distance relaying; however, the results shown in (18) are influenced by the fact that the fault current is modified with the addition of residual current multiplied by the K_0 factor [3].

V. Distance Element Setting Criteria for DG Applications

In this distance-based feeder protection application, the high-set instantaneous overcurrent elements 50 H or 50 NH are replaced with instantaneous quadrilateral distance elements. The sensitive low-set instantaneous elements 50 L or 50 NL are replaced with an instantaneous mho element, while the 51 time-overcurrent elements are maintained and torque-controlled by

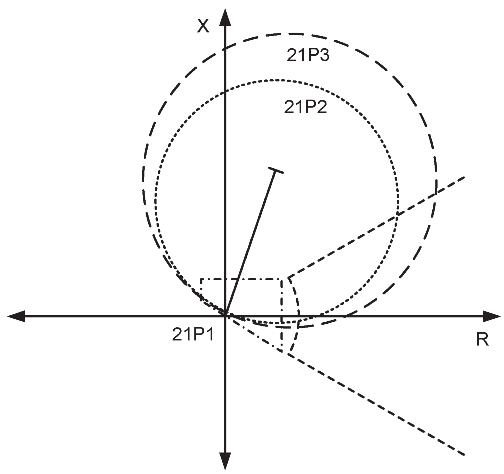

Fig. 7. Phase distance elements.

mho elements. The primary goals of the distance-based feeder protection scheme are to perform the following:

1) quickly clear temporary faults up to the end of the zone, maintaining the fuse-saving philosophy;
2) provide stepped remote backup protection for feeder sections beyond downstream reclosers;
3) provide secure directional supervision to discriminate between forward and reverse faults;
4) provide fast clearing of faults up to the first critical primary fuse in order to limit transformer through-fault damage;
5) provide improved coverage for high-resistive close-in faults;
6) provide shaping capabilities to limit the reach on tapped load stations;
7) provide improved setting flexibility to deal with the desensitizing effect of tapped DG on the feeder;
8) provide feeder coverage that is relatively immune to variations in source impedance;
9) provide unbalanced load encroachment to cater to lateral fuse failures on long lines with DG;
10) facilitate the evolution from radial to nonradial feeders.

Similar to the overcurrent scheme following the initial reclose, the sensitive low-set instantaneous mho equivalent protection elements are blocked, and the 51 protection elements coordinate as in the overcurrent-based feeder protection, with distance elements providing torque control. This makes the overcurrent element directional, as is generally required on feeders with large amounts of DG.

Protection for phase faults is shown in Fig. 7.

The 21P1 element is set to underreach the first lateral fuse and is never blocked. In cases (where this fuse is too close to the station) that would limit the reach of the 21P1 element and minimize the effectiveness of this high-set instantaneous protection, the overreaching of the fuse is accepted, provided that the total operating time of the feeder protection plus breaker operating time is greater than the total clearing time of the fuse with margin.

In applications where there is no midline recloser, 21P2 is the low-set instantaneous fuse-saving element and is set

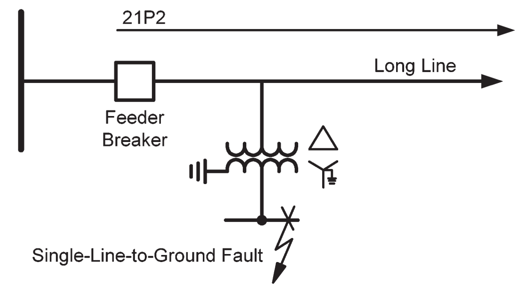

Fig. 8. Risk of zone 2 operation for low-voltage faults.

at 125%–150% of the maximum apparent feeder impedance (i.e., the impedance seen by the relay when the generator is connected with a minimum system behind the relay and the DG source is maximized). The reach settings should be checked to avoid tripping for a fault on the low-voltage side of a tapped transformer. Normally, the transformer will provide sufficient impedance to prevent this, but tripping can occur in the case of a long line and/or a large tapped load. Fig. 8 illustrates the potential for operation of the 21P2 element for a ground fault downstream of a distribution transformer.

In applications where a midline recloser is present, 21P2 is set for high-speed clearing and underreaches the midline recloser. In this case, overreaching is not acceptable, so 21P2 is set at 75%–80% of the positive-sequence line impedance. The 21P3 torque controls the 51P element and is set at 150%–200% of the maximum apparent feeder impedance, protecting the entire feeder beyond all midline reclosers and lateral fuses to the end of the feeder. In applications where a midline recloser exists, the 21P3 element is set to see the entire feeder and includes a low-set instantaneous 100-ms-delayed trip, providing the sequence coordination required for a fast curve trip from the recloser to be detected by the feeder protection and block this 100-ms-delayed trip path. The 100-ms trip path also provides the fuse-saving protection for the portion of the feeder between the 21P2 element and the midline recloser. The recloser total clearing time (protection time plus the interrupter open interval time) should be checked to ensure that there is adequate margin. In addition, the 21P3 element provides definite-time backup protection for telecommunications cables located on the same right of way that may otherwise be damaged because of induced ground current in the sheath.

The maximum apparent impedance is used when setting both the 21P2 (when there is no midline recloser) and 21P3 elements.

The distance elements applied for a ground fault are illustrated in Fig. 9.

The zone 1 ground 21G1 element replaces the ground high-set instantaneous 50 NH element and is set to underreach the first lateral fuse. In applications where there is no midline recloser, 21G2 is used as the instantaneous fuse-saving element, as is the case for the phase protection element. 21G3 is a supervision element set to supervise 51 N. This element is intended to overreach and is set at 150%–200% of the apparent feeder impedance.

The 51 N element is set to coordinate with both upstream and downstream devices, as is detailed in the overcurrent feeder

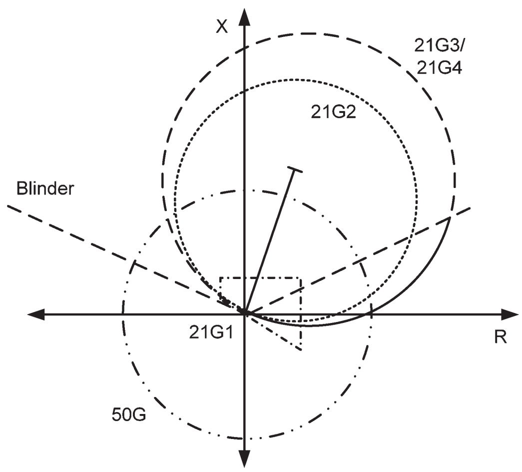

Fig. 9. Ground distance elements.

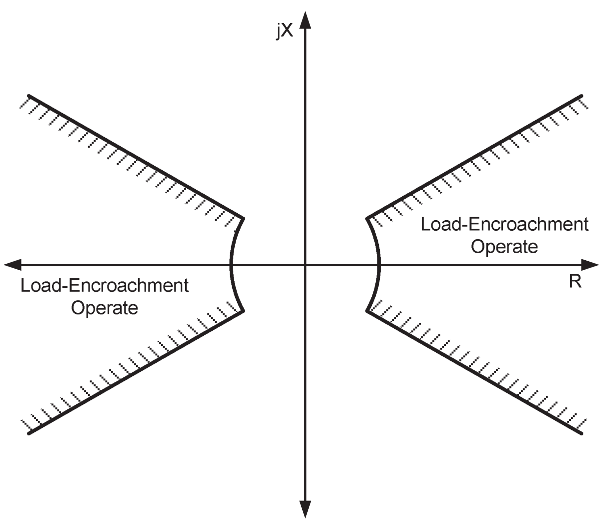

Fig. 10. Load-encroachment characteristic.

protection scheme. The 51 N overcurrent element forward and reverse fault discrimination is achieved by using the directionality provided by the 21G3 element. Hydro One Networks, Inc., requires that, when the DG source is tripped because of a feeder fault, then the ground source associated with the distributed generator also needs to be isolated so that time coordination after reclosing is based on all downstream generators being removed, similar to a conventional radial feeder.

The impedance characteristics should be checked to ensure sufficient coverage for high-resistance faults. This is important for short lines where the reduced reach settings may limit the fault resistance coverage.

To improve the security of the phase distance or phase overcurrent elements on heavily loaded feeders, load encroachment is used.

The load-encroachment element operates as follows. The element measures the apparent positive-sequence impedance being supplied by the feeder. If the measured positive-sequence impedance falls within the load-encroachment region shown in Fig. 10, the load-encroachment output is asserted. The output

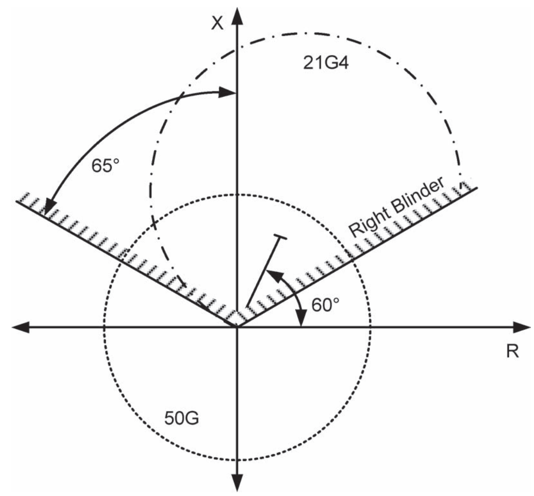

Fig. 11. Coverage provided by zone 3 and zone 4.

from the load-encroachment logic blocks the phase distance and phase overcurrent elements from operating.

This phase load-encroachment element is based on the assumption that load is a balanced condition, which is acceptable for the transmission system. However, on the four-wire distribution system, load can sometimes become quite unbalanced. Utilities must manage unbalanced load that is due to the loss of a single-phase lateral or simply unbalanced load from sections of the feeder that may not be under utility control. In an effort to provide a load-encroachment element that allows for unbalanced loads and accommodates the compensated distance elements in this distance-based feeder protection, a fourth distance element is used. The 21G4 element is set at the same reach as the 21G3 element and includes blinders, as shown in the neutral load encroachment of Fig. 11.

The 50G element is set at 150% of the maximum expected load unbalance. This worst-case maximum load unbalance would typically be created when a heavily loaded single-phase lateral fuse is blown.

The ground or compensated load encroachment is provided with the following logic.

1) Low set = (21G4 OR 50G) AND 21G2.
2) Timed (overcurrent) = (21G4 OR 50G) AND 21G3 or 51 N torque-controlled by 21G3.

This distance-based feeder protection has two additional backup settings. The first backup setting is a definite-time trip, where both 21G3 and 21P3 are set to trip after they have been asserted for 2.8 s, providing telecommunications cable sheath protection. A second backup trip is set as a current-only condition. This trip is set with a definite-time delay on the low-set phase elements with fuse failure supervision to cater for voltage transformer (VT) fuse failure conditions. The 50 L and 50 NL elements used in this backup protection are set as described in the overcurrent feeder protection but with a definite-time delay. Both of these backup settings are set to clear low-magnitude or lateral faults that fail to be tripped in less than 3 s by the torque-controlled 51 and 51 N elements.

TABLE I
SYSTEM PARAMETERS

	Real pu	Imag pu	Mag pu	Ang
Z1 SYS	0.0265	0.3681	0.3691	85.9
Z0 SYS	0.0004	0.3099	0.3099	89.9
Z1 Fuse	0.1340	0.5310	0.5476	75.8
Z0 Fuse	0.3640	1.4380	1.4834	75.8
Z1S	0.2680	1.0620	1.0953	75.8
Z0S	0.7280	2.8760	2.9667	75.8
Z1H	0.9255	1.7105	1.9448	61.6
Z0H	2.2159	4.9648	5.4369	65.9
Z1 Feeder	1.1935	2.7725	3.0185	66.7
Z0 Feeder	2.9439	7.8408	8.3753	69.4
Z1 TX (G1, G2)	0	0.5750	0.5750	90
Z0 TX (G1, G2)	0	0.5000	0.5000	90
Xd” (G1, G2)	0	1.6060	1.6060	90

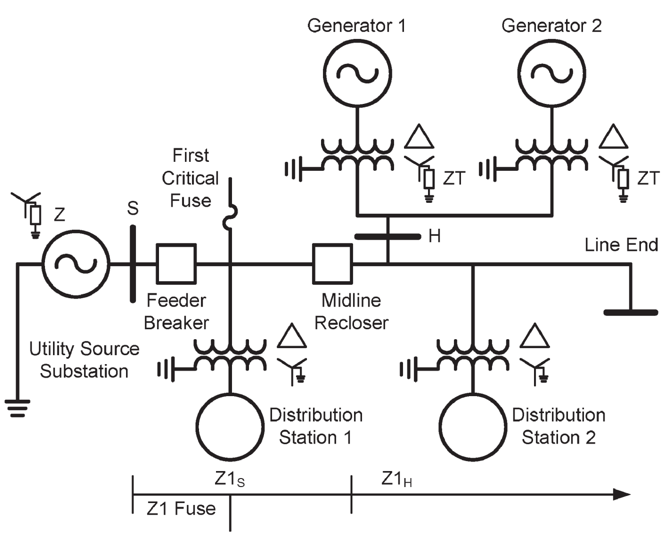

Fig. 12. Sample system.

VI. SAMPLE FEEDER MODEL WITH DG

The following system is used to review the application of distance protection on feeders. Table I and Fig. 12 provide the data for the sample system.

The sample system has a per-unit base of 27.6 kV and 100 MVA.

The zero-sequence impedance of the G1 and G2 transformers excludes the neutral reactor impedance. A 10-Ω neutral reactor is used in the neutral of TX G1 and TX G2 for this sample system.

All impedance values are calculated in Ω primary. Typically, relay reach settings are entered in Ω secondary, requiring a conversion using the current transformer (CT) and VT ratios.

We assume that the impedance relay allows the ground fault compensation factor K_0 to be entered directly, allowing ground distance reach settings to be specified in terms of positive-sequence impedance

$$K_0 = (Z0/Z1 - 1)/3 = 0.5921 \text{ at } 4.2^\circ \tag{20}$$

where

Z0 zero-sequence impedance of the Z0 feeder;
Z1 positive-sequence impedance of the Z1 feeder from Table I.

In this example, 21P1 and 21G1 are never blocked and are set to underreach the first critical fuse. These elements provide fast clearing for close-in feeder faults and limit the impact of through-fault current on station transformers.

The positive-sequence impedance to the first critical fuse is 4.17 at 76° Ω as calculated using the data from Table I. For security purposes, the 21P1 zone is set to reach 80% of this value. Recall that this element has a quadrilateral characteristic. The characteristic will intersect the reactive axis at $0.8 \bullet 4.17\ \sin(76) = 3.23\ \Omega$. The left blinder is set to intersect the resistive axis at the same value of 3.23 Ω, and the right blinder is set to no greater than five times the reactive reach or $5 \bullet 3.23 = 16.15\ \Omega$. In this case, the right blinder is set to 12.0 Ω. We verify the maximum load at the right blinder reach $[(27.6\text{ kV})^2/(12 + j3.23)\ \Omega = 61\text{ MVA}]$. We reduce the resistive reach, as required, so that the maximum load or inrush current will not encroach on 21P1.

The 21G1 element is set to underreach the first critical fuse by 25%. This element also has a quadrilateral characteristic and is set to intersect the reactive axis at $0.75 \bullet 4.17\ \sin(76) = 3.03\ \Omega$. The left blinder is also set to intersect the resistive axis at 3.03 Ω, and the right blinder is set at five times the reactive reach or $5 \bullet 3.03 = 15.15\ \Omega$. In this case, the right blinder is set to 12.0 Ω.

This example includes a midline recloser, and therefore, 21P2 and 21G2 are set to underreach the recloser. The zone 2 elements, in this case, are instantaneous and are blocked for a limited time after the first trip to allow for timed trip coordination following the reclose. If the midline recloser is not available, then 21P2 and 21G2 are set to 150% of the maximum apparent impedance (with all generation connected) for a feeder-end fault.

The 21P2 element is set to reach up to 80% of the positive-sequence line impedance to the recloser. The positive-sequence line impedance is 8.33 Ω. The 21P2 reach is $0.80 \bullet 8.33 = 6.66\ \Omega$. The equivalent setting for a relay with a line characteristic of 60° is calculated as $6.66\ \Omega/\cos(76 - 60) = 6.93\ \Omega$. This setting of 6.93 Ω provides a reach of 6.66 at 76° Ω, which is 80% of the positive-sequence impedance at 76°. We now check the maximum load in MVA at the maximum expected load angle of 30° $[(27.6\text{ kV})^2/(6.93\ \Omega \bullet \cos(60 - 30)) = 127\text{ MVA}]$. We supervise this element using the relay load-encroachment characteristic if the maximum load encroaches on the 21P2 characteristic.

The 21G2 element is set to reach up to 75% of the positive-sequence line impedance to the recloser. The positive-sequence line impedance is 8.33 at 76° Ω. The 21G2 reach is therefore $0.75 \bullet 8.33$ at $76^\circ = 6.25$ at 76° Ω. The equivalent setting for a relay with a line characteristic of 60° is calculated as

$6.25\ \Omega/\cos(76-60) = 6.50$ at $60°\ \Omega$. This setting of 6.50 at $60°\ \Omega$ provides a reach of 6.25 at $76°\ \Omega$, which is 75% of the positive-sequence impedance at 76°.

For this example, where 21P2 and 21G2 underreach the midline recloser, 21P3 and 21G3 are set to torque-control the inverse-time overcurrent elements. The zone 3 impedance elements together with the inverse-time overcurrent elements provide time coordination following the reclose that allows for reclosers or fused laterals to trip, as required. Because the zone 2 impedance elements are set to underreach the recloser, the zone 3 elements are allowed to trip for an initial fault after a 100-ms delay. This definite-time trip is blocked following the first trip. This delay allows for the recloser to operate for downstream faults while still maintaining fast clearing for faults between the substation and the recloser.

A check of the apparent impedance due to the DG infeed is carried out as follows. A line-end three-phase fault is calculated in the following:

$$\mathrm{I3F} = \frac{V_{\mathrm{SYS}}}{\frac{(Z1_{\mathrm{SYS}}+Z1_{S})\bullet Z1_{\mathrm{DG}}}{Z1_{\mathrm{SYS}}+Z1_{S}+Z1_{\mathrm{DG}}} + Z1_{H}} = (320-762j)\ \mathrm{A} \tag{21}$$

where

$Z1_{\mathrm{SYS}}$ base system impedance;

$Z1_{H}$ line impedance minus the impedance from S to the midline recloser;

$Z1_{S}$ impedance from S to the midline recloser;

$Z1_{\mathrm{DG}}$ total impedance of DG1 plus the impedance of the DG1 transformer in parallel with the impedance of DG2 plus the impedance of the DG2 transformer.

All are positive-sequence values from Table I.

The contribution from the substation is the following:

$$\mathrm{I3F}_{\mathrm{SYS}} = \frac{\mathrm{I3F}\bullet Z1_{\mathrm{DG}}}{Z1_{\mathrm{SYS}}+Z1_{S}+Z1_{\mathrm{DG}}} = (174-309j)\ \mathrm{A}. \tag{22}$$

The DG contribution is as follows:

$$\mathrm{I3F}_{\mathrm{DG}} = \frac{\mathrm{I3F}\bullet (Z1_{\mathrm{SYS}}+Z1_{S})}{Z1_{\mathrm{SYS}}+Z1_{S}+Z1_{\mathrm{DG}}} = (145-452j)\ \mathrm{A}. \tag{23}$$

The increase in apparent impedance is the following:

$$Z1_{H\_\mathrm{NEW}} = \frac{\mathrm{I3F}_{\mathrm{DG}}\bullet Z1_{H}}{\mathrm{I3F}_{\mathrm{SYS}}} = (12.8+15.2j)\ \Omega. \tag{24}$$

The following is the apparent impedance with DG connected, expressed in per unit of the actual line impedance:

$$\left|\frac{Z1_{\mathrm{LINE}}+Z1_{H\_\mathrm{NEW}}}{Z1_{\mathrm{LINE}}}\right| = 1.84 \text{ at } -8° \text{ pu}. \tag{25}$$

Consequently, 21P3 is set to 200% of the maximum apparent impedance. The impedance will typically overreach considerably under maximum apparent impedance conditions due to a large source impedance and a lower tapped generation impedance. The three-phase feeder-end fault, with minimum fault current from the utility and maximum fault current from the DG, results in $42.3\ \Omega$ at 59°. The 21P3 reach is $2\bullet 42.3\ \Omega$ at $59° = 84.6\ \Omega$ at 59°. This setting is adjusted for a relay characteristic angle of 60°, and the setting becomes $84.6\ \Omega/\cos(59-60) = 84.7\ \Omega$ at 60°. We now check the maximum load in MVA at the maximum expected load angle of 30° $[(27.6\ \mathrm{kV})^2/(84.7\ \Omega\bullet\cos(60-30)) = 10.38\ \mathrm{MVA}]$. We include the load-encroachment characteristic if the maximum load encroaches on the 21P3 characteristic.

The 21G3 element is set to 200% of the maximum apparent impedance. A single-phase-to-ground feeder-end fault, with minimum fault current from the utility and maximum fault current from the DG, results in $43.6\ \Omega$ at 59°. The 21G3 reach is $2\bullet 43.6\ \Omega$ at $59° = 87.2\ \Omega$ at 59°. This setting is adjusted for a relay characteristic angle of 60°, and the setting becomes $87.2\ \Omega/\cos(61-60) = 87.2\ \Omega$ at 60°.

VII. Impact of Distance Relaying on Feeder Protection Cost

The addition of generation usually requires that feeder protection be upgraded to permit directional supervision of overcurrent functions. Today, the difference in product cost between a distance relay and a directional overcurrent relay is minimal relative to the installation cost. The protection engineer needs only to specify what protection elements are required, and the various solutions are very close in material, engineering, and installation costs. The feeder breaker is normally located in a station where VTs are already available and connected to the bus. These VTs can be used for directional overcurrent protection and distance protection, as well as load information for each feeder from the intelligent electronic device (IED). The IED voltage inputs are designed to have high input impedances, so connecting multiple feeder protective relays to a single set of bus VTs is usually not a problem. Where space is an issue, the VT can be installed on the feeder, but this is not the most cost-effective solution because the life-cycle cost of having VTs on every feeder is greater than having a single set of three VTs on the bus. Existing three-wire systems may be limited to two phase-to-phase VTs on the bus. Full functionality of the distance relaying presented in this paper requires three phase-to-neutral connected VTs.

VIII. Learning Curve for Distance Protection Applications

Distance relaying has an arguable advantage compared with overcurrent relaying in that the protection engineer can define zones of protection in the form of reach settings based on circuit impedances. However, there are sometimes subtle aspects related to wiring and setting a distance relay that may not be immediately obvious to someone who is unfamiliar in the field. For instance, a grounded-wye VT connection is required, in most cases, for the correct operation of a ground distance element—a fact that may escape an inexperienced protection engineer. Often, a protection engineer may be responsible for either distribution or transmission but not both and, in such cases, will be well versed in one field but not the other. In some cases, a distribution company may need to agree to a one-time investment in training the protection and control staff in distance protection. Given the benefits of distance protection, this investment is well justified. There are many options for the required training.

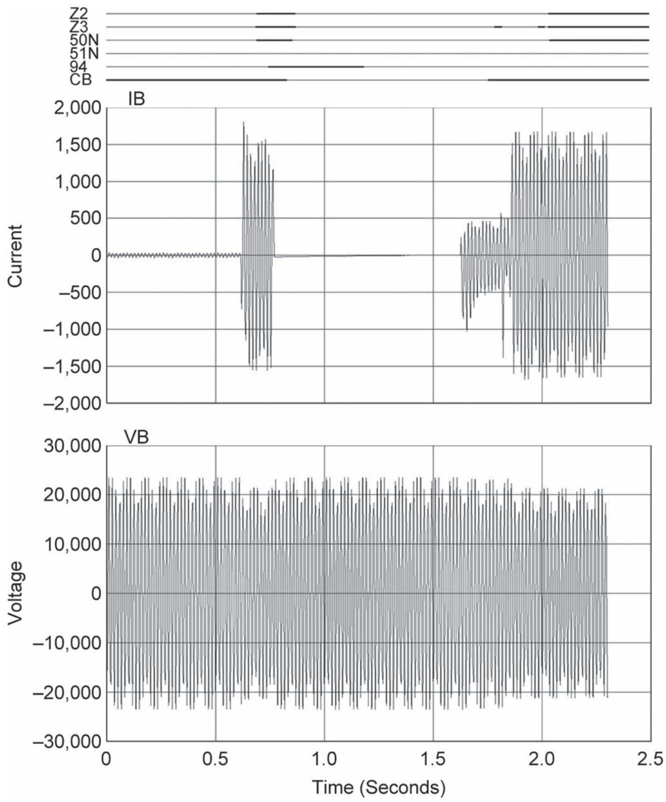

Fig. 13. Time plot for case 1.

Relay manufacturers usually offer transmission relay training for their products, including procedures for setting and testing. Methods for analysis of distance relay operations, an important but sometimes overlooked task, may also be included. This training can take the form of conventional classroom instruction, website-based training, or instructional DVDs. Such training will typically be product-specific and may assume a basic level of knowledge. In addition, several relay schools provide more comprehensive and generic training for both distribution protection and transmission protection. These schools may prove better sources of instruction but will likely entail travel to a training center.

In the past, colleges and universities have not been the best sources for instruction on protective relaying. Now, an increasing number of institutions are providing detailed levels of both theoretical and practical instructions. When locally accessible, this avenue, while requiring a longer and higher level of commitment from the student, can provide the best outcome.

IX. Case Studies

The distance scheme described in Section V has been used in several applications. The following cases show faults on protected feeders and the resulting relay behavior.

A. Case 1

Figs. 13 and 14 show a BG fault on a feeder with DG and a midline recloser. The zone 2 reach has been reduced to prevent a pickup for faults downstream from the recloser. The initial fault is cleared by zone 2 after a delay of 50 ms. The line subsequently recloses. The re-energization current includes a significant inrush component. After 230 ms, a second fault occurs. For the second fault, zone 2 is blocked, and the relay begins to time out on the 51 N element supervised by zone 3 (pickup flag is not shown). Fig. 13 shows the B-phase voltage and current, and the relay internal flags.

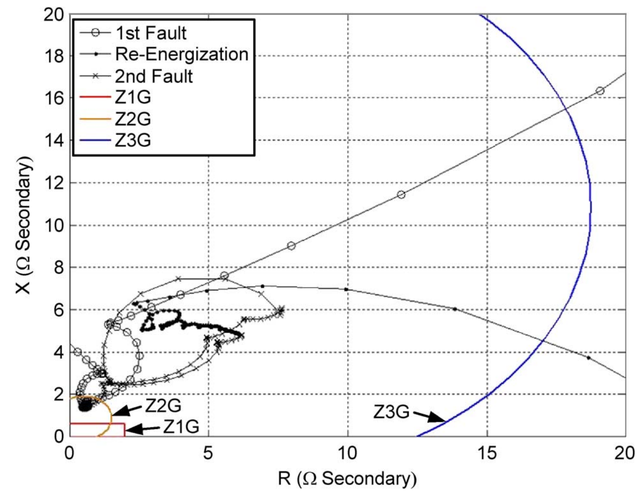

Fig. 14. Impedance plot for case 1.

Fig. 14 is an impedance plot showing the first fault, the re-energization, and the second fault.

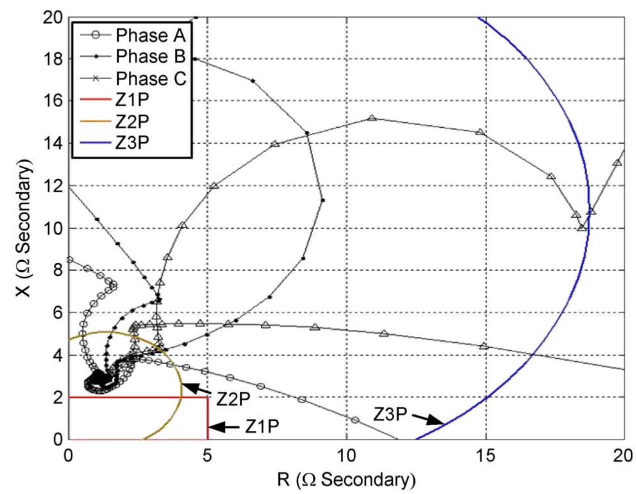

Fig. 15. Impedance plot for case 2.

B. Case 2

This case shows a relay operation for a feeder with DG. This feeder also has a midline recloser. In this case, the feeder is importing power prior to an ABC fault occurrence. The fault is inside the zone 2 characteristic (Fig. 15). The relay takes one-half of a cycle to detect the fault. The feeder successfully recloses (Fig. 16).

The load current is significantly higher following reclose, owing to the loss of local generation.

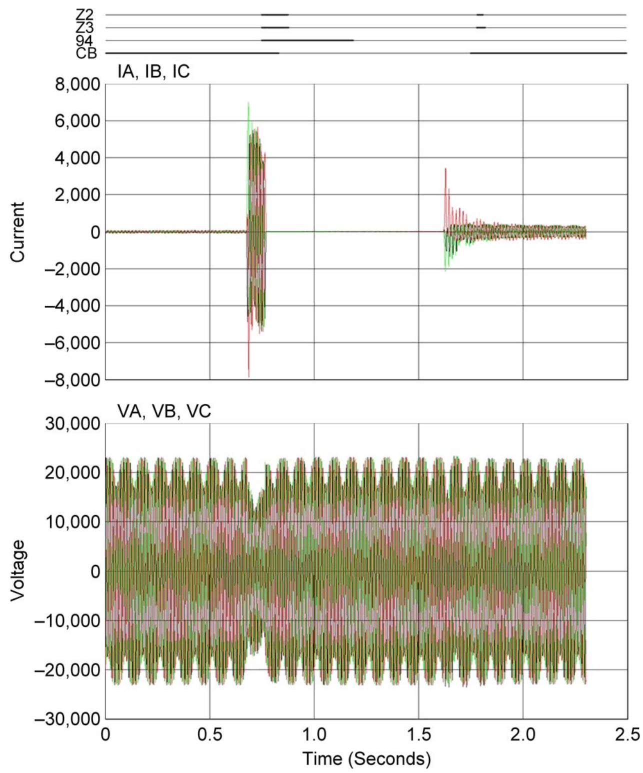

Fig. 16. Time plot for case 2.

X. Conclusion

The addition of DG can result in a loss of protection sensitivity, a loss of protection coordination, and a tripping for out-of-zone faults. Distance relays are useful in addressing these challenges. Distance relays are inherently directional, have operating characteristics that can be shaped, and are influenced less than overcurrent relaying by changing system conditions.

This paper has outlined a methodology for the application of distance relaying to feeders that include generation. The approach preserves the sensitivity and effectiveness of fuse-saving schemes.

The methodology has been successfully applied, as evidenced by the presented relay event files.

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