Prevent False Tripping Due to Grounding Bank Backfeed

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***Abstract*—Sometimes distribution systems contain grounded-wye primary delta secondary transformer banks, especially at distributed energy resource (DER) sites or where only three-phase loads are served. These same transformer banks also serve as grounding banks, sometimes unintentionally, and provide a pure zero-sequence current to ground faults anywhere on the same distribution system. This contribution can cause classically applied distribution protection relays to trip for out-of-zone faults on phase or ground overcurrent elements. The paper reviews the use of directional overcurrent elements that combine voltage and current measurements as a classical solution but also introduces a novel technique that uses only current measurements, which is applicable where no voltage measurements are available.**

I. Introduction

An electric cooperative in the Southern U.S. (Co-op) has experienced several unexpected trips of a recloser on one of their distribution feeders. These trips were determined to be the result of a grounding bank downstream that sourced high currents through the recloser for faults upstream of the recloser.

This is a well-documented problem with classical solutions that either sacrifice sensitivity or require additional instrumentation. The most common solution is to implement directional overcurrent protection, which requires voltage measurements that are often not present with legacy distribution protection equipment. However, the Co-op sought a solution that optimized sensitivity, dependability, and security using existing equipment.

This paper explains why these types of transformer banks exist in the distribution system, how they challenge traditional distribution protection, and how distribution protection can be secured against undesired tripping for out-of-zone faults in the presence of such transformers. Finally, the paper introduces a novel method for securing distribution protection using only current measurements, which can be implemented even with legacy distribution protection equipment.

II. Wye-Delta Transformers in Distribution Systems

Most electric power distribution systems in North America are built and operated as a multigrounded neutral four-wire system [1]. With the presence of a grounded neutral, many utilities have adopted the practice of installing three-phase transformer banks to serve loads with the primary windings connected in a grounded-wye configuration. This arrangement helps avoid the risk of ferroresonance [2] and allows the use of single-bushing transformers for both single- and three-phase banks, simplifying a utility's construction and stocking practices.

However, there is some variance in utility consumer needs that may result in different secondary arrangements throughout a utility's service territory. Reference [3] defines three-phase services commonly supplied to utility consumers. These include the four-wire wye, the three-wire delta, and the four-wire delta. The four-wire wye is common, as it provides three single-phase-to-ground circuits that can be combined to serve a single three-phase load. Such a service is supplied through a wye-wye transformer connection, in which the neutral on primary and secondary are typically bonded to the same ground to mitigate the risk of ferroresonance and limit service-voltage-to-ground to rated service insulation levels.

On the other hand, some utility consumers may only have three-phase loads and may seek ground isolation from the utility. A common way to meet this need is to supply a three-wire delta service. If the utility's common practice is to connect their transformer bank primary as a grounded wye, it results in a grounded-wye delta transformer connection, which is known to serve as a grounding bank also. This behavior is explained in the next section. The existence of such banks on the distribution system is often the unintentional result of following typical construction practices while seeking to meet a utility consumer's stated requirements.

The four-wire delta service is another commonly applied service. This service provides two single-phase-to-ground circuits to a consumer while also providing a three-phase circuit that shares a common leg with the single-phase circuits. It can be built using three transformers but is often made available to utility consumers through the use of two transformers, in what is known as an open-wye open-delta transformer bank (see Fig. 1). Such a bank is economical but is also known to impose unbalanced impedances in series with a balanced load, resulting in unbalanced current demand even with a balanced supply voltage. For static loads, this unbalance may go unnoticed and, even for motors, may be acceptable if the motor is loaded lightly enough. However, if a motor is operated with little margin on such a bank, the unbalance may be excessive and require the utility to close the delta by adding a third transformer, as in the bottom image of Fig. 1. Again, this creates the grounded-wye delta grounding bank, perhaps unintentionally. Reference [4] gives examples of analyses of four-wire delta services under steady-state loading conditions, illustrating the higher potential for unbalance in open-delta banks.

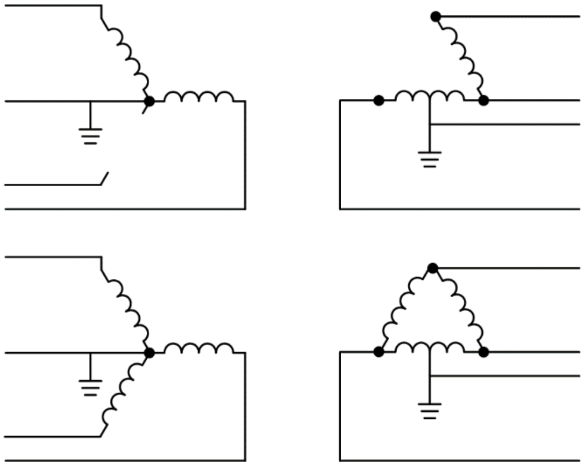

Fig. 1. Four-wire delta service using an open-wye open delta (top) and a grounded-wye delta (bottom).

With the proliferation of distributed energy resources (DERs), utilities are motivated to intentionally install a grounded-wye delta transformer at the point of common coupling (PCC) because the ungrounded secondary isolates the DER grounding system from the utility grounding system; this allows the generation equipment to be grounded however the owner sees fit. The grounded-wye primary with delta secondary creates a grounding bank, which, in turn, limits overvoltages on the utility's unfaulted phases during a utility system ground fault sourced by the DER. IEEE 1547 [5] requires that DER output limit overvoltages to 138 percent or less. In some cases, the neutral may be grounded through an impedance that is selected to be large enough to limit fault current contribution but small enough to still limit overvoltage. In many cases, however, the neutral is effectively grounded.

III. Grounding Bank Behavior

Grounding banks are transformer banks that provide a path for zero-sequence current to flow from a grounded neutral to a ground fault on a phase conductor. Grounded-wye delta and zigzag winding arrangements are the most commonly applied configurations for grounding banks. Grounded-wye delta banks can be built using standard service transformers that a distribution utility may already keep in stock, so they are more typically applied in distribution systems. The remainder of this paper addresses the use of grounded-wye delta transformer banks only.

It may not be intuitively obvious how a grounding bank can source current to a fault on the primary side, even when there is not an active source on its secondary. It is ultimately the response of the transformer to the unbalanced voltages that it is subjected to during a ground fault. Fig. 2 shows the behavior of a grounding bank with the grounded-wye primary connected to a distribution system with balanced voltages. Note that the phasor sum of these voltages, 3V0 = Va + Vb + Vc, imposes a net voltage around the delta of 0 V, resulting in no current circulating in the delta, therefore, no current flowing in the coupled-wye windings.

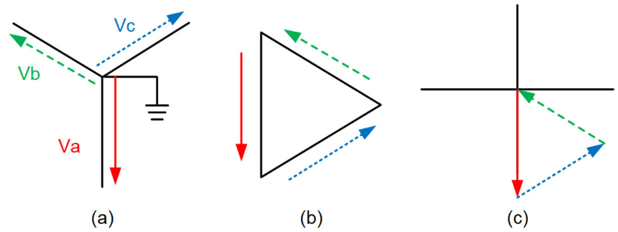

Fig. 2. Balanced voltages applied to (a) the grounded-wye primary resulting in (b) balanced voltages on the delta secondary. The phasor sum of these voltages (c) is zero.

Fig. 3 shows the same bank attached to the same distribution system, but now subjected to unbalanced voltages due to a distribution system ground fault on the A-phase. Va is now depressed, resulting in unbalanced voltage applied to the delta winding. The phasor sum of these voltages, 3V0 = Va + Vb + Vc, is no longer zero. The zero-sequence current I0 now circulates in the delta winding as the result of 3V0 impressed across the sum of the winding impedances. The I0 circulating in the delta windings couples I0 into each phase of the wye winding. 3I0 must flow up the neutral in order for I0 to flow out of all three phase windings. In this way, with no active source connected to the delta secondary, the grounding bank provides a path for 3I0 only, so it appears to be a pure zero-sequence source. The word *source* is a misnomer, since the bank does not actually generate the zero-sequence current. But in the sense that the 3I0 flows from the grounding bank towards the fault, it is common industry practice to refer to a grounding bank as a zero-sequence source.

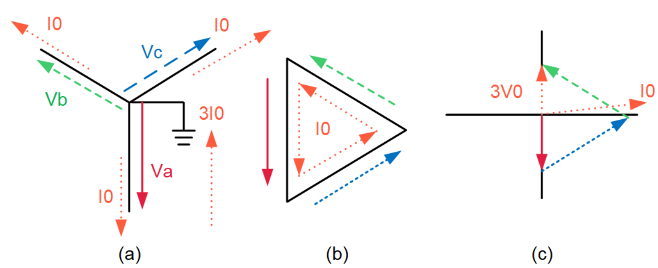

Fig. 3. Unbalanced voltages applied to (a) the grounded-wye primary resulting in (b) unbalanced voltages on the delta secondary. The phasor sum of these voltages (c) is not zero, causing I0 to circulate in the delta (b) and couple to wye windings (a).

This behavior is well modeled in sequence network theory by showing the grounding bank in the zero-sequence network as an open circuit on the delta side, and as the winding impedance from the common bus to the active bus as a path through which zero-sequence current flows from the common bus. If there is no load connected to the delta secondary, the connections on the delta side of the transformer are simply not connected to anything and remain an open circuit. Fig. 4 shows an example distribution system with a grounded-wye delta transformer serving as a grounding bank at the end of the feeder, and Fig. 5 shows the resulting positive-, negative-, and zero-sequence network models for the feeder of interest, FA, in the example. References [6], [7], and [8] are good resources to learn more about the practical application of symmetrical components and sequence networks to model the unbalanced behavior of three-phase power systems.

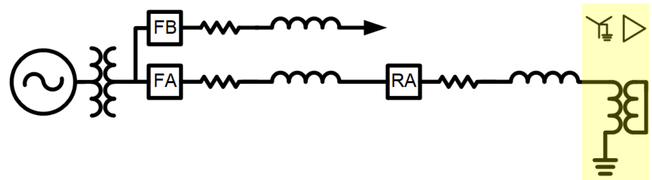

Fig. 4. Example distribution feeder with grounding bank (highlighted) at the end.

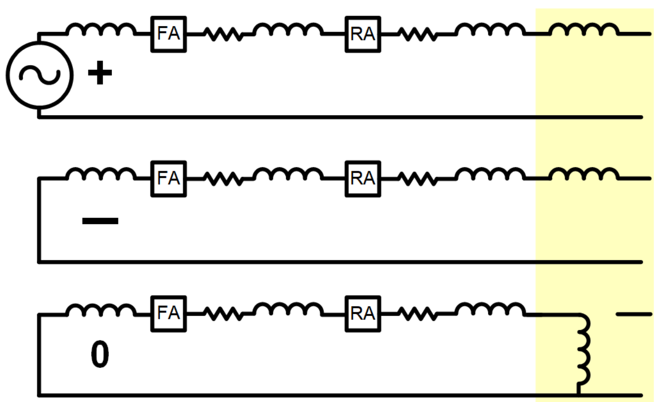

Fig. 5. Sequence network model of example feeder with grounding bank (highlighted) at the end.

When these sequence networks are connected together to model ground fault behavior, we can now see the challenge a grounding bank poses to traditional distribution protection. The example feeder has an active source only at one end, and as a result, the load current only flows in one direction. If not for the grounding bank, the fault current would also flow only in one direction. Since most distribution feeders do not have grounding banks on them, distribution utilities classically apply simple nondirectional overcurrent (50) and inverse-time overcurrent (51) protection elements to protect their feeders. The assumption is that, for example, if there is a fault between the feeder breaker FA and the downstream recloser RA, RA sees no fault current and, therefore, does not trip.

With the introduction of a grounding bank, this assumption is no longer valid, as shown in Fig. 6. We can see here that a significant zero-sequence current may flow from the grounding bank towards the fault, passing through the recloser RA. This appears to the recloser control as pure zero-sequence current; that is, all three phase currents are the same magnitude and in phase (or very nearly so). This pure zero-sequence current very likely exceeds the pickup of 51G ground protection elements and, in some cases, can be high enough to exceed the pickup of 51P phase protection elements.

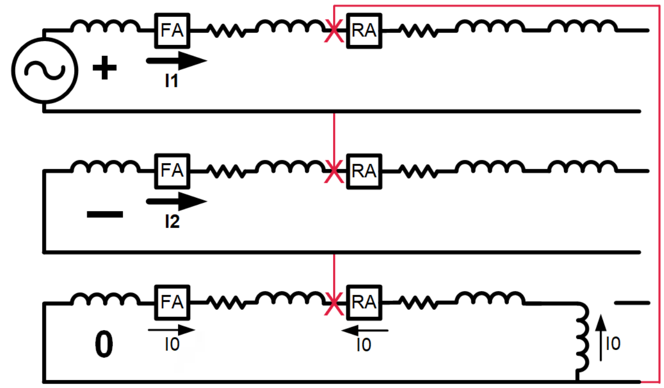

Fig. 6. Sequence network model of example feeder with a single-line-to-ground fault applied between FA and RA.

IV. Real-World Example

The Co-op has experienced this phenomenon of a grounding bank downstream causing unexpected trips of a recloser on one of their 25 kV distribution feeders that serves a large industrial facility at 25 kV through a primary metering installation. Their situation introduces yet another case in which a utility may have a grounding bank on their system. In this case, their consumer, desiring to supply large 2,400 V motor loads with a three-wire supply, has installed several large grounded-wye delta transformers within their own facility, an action that affects the utility but is outside of their control.

This problem came to the utility's attention when they began to experience extended outages on the portion of their feeder between a recloser on the feeder and their large consumer, even when the initiating fault was found upstream of the recloser. Initially, they noticed that the feeder breaker tripped, then they found the faulted section, made repairs, and closed the feeder breaker to energize the feeder, expecting service to be restored to all consumers on the feeder. However, as consumers downstream of the recloser called in to report the continued outage, linemen were dispatched to the recloser location, finding it open as well. Not yet knowing the cause of this, the linemen searched for evidence of an additional fault downstream of the recloser. Eventually, not finding such evidence, they closed the recloser and restored power to the remaining consumers. This can be described using the topology given in Fig. 4; the fault was found between FA and RA, yet FA and RA both were found to be tripped and locked out, resulting in extended outage for consumers downstream of RA. Once this occurred a few times, the Co-op's engineers knew more investigation was merited. Following one such event, they downloaded Sequential Event Recorder (SER) reports from both the feeder relay and the recloser control, and they began to see the first evidence of this phenomenon. The data in Fig. 7 show that the feeder breaker relay and the recloser control both saw fault current and their 51 elements began timing to trip, but the recloser control timed out and tripped well before the feeder breaker relay. This proves the fault was upstream of the recloser, since the fault was not cleared when the recloser tripped. From that point forward, the feeder breaker continued reclosing and tripping until it locked out, but the recloser never saw healthy voltage again to facilitate a reclose, so it also went to lockout.

Feeder

636	12/21/20	08:03:36.980	51P1	Asserted
635	12/21/20	08:03:36.980	OUT103	Asserted
634	12/21/20	08:03:37.018	51N1	Deasserted
633	12/21/20	08:03:37.022	51P1	Deasserted
632	12/21/20	08:03:37.026	OUT103	Deasserted
631	12/24/20	01:05:17.658	51P1	Asserted
630	12/24/20	01:05:17.662	51N1	Asserted
629	12/24/20	01:05:17.662	OUT103	Asserted
628	12/24/20	01:05:18.579	51N1	Deasserted
627	12/24/20	01:05:18.808	51P1T	Asserted
626	12/24/20	01:05:18.808	79CY	Asserted
625	12/24/20	01:05:18.808	79RS	Deasserted
624	12/24/20	01:05:18.808	OUT101	Asserted
623	12/24/20	01:05:18.808	OUT104	Asserted
622	12/24/20	01:05:18.808	TRIP	Asserted
621	12/24/20	01:05:18.825	IN105	Deasserted

Recloser

302	12/21/20	08:04:17.033	SH1	Deasserted
301	12/21/20	08:04:17.033	SH0	Asserted
300	12/24/20	01:05:17.740	51G1T	Asserted
299	12/24/20	01:05:17.740	79CY	Asserted
298	12/24/20	01:05:17.740	79RS	Deasserted
297	12/24/20	01:05:17.740	TRIP	Asserted
296	12/24/20	01:05:17.819	52A	Deasserted
295	12/24/20	01:05:17.828	51G1T	Deasserted
294	12/24/20	01:05:17.849	59A1	Deasserted

Fig. 7. SER reports from a feeder relay and a recloser control showing the recloser tripping for a fault between the feeder and recloser.

The feeder SER report in Fig. 7 shows that the feeder relay captured oscillographic event records when its 51 elements picked up (while the recloser was still closed) and when it tripped (after the recloser had already tripped). Fig. 8 shows the two event records side by side. In the first event, (a), when the single-line-to-ground fault begins, I0 is roughly half the magnitude of I1 and I2 while the grounding bank is still connected. After the recloser has tripped and the grounding bank has been isolated, the second event, (b), shows the more familiar signature of a single-line-to-ground fault in which I1, I2, and I0 are all equal. The recloser control also captured an event report in which almost pure zero-sequence current passes through it, shown in Fig. 9.

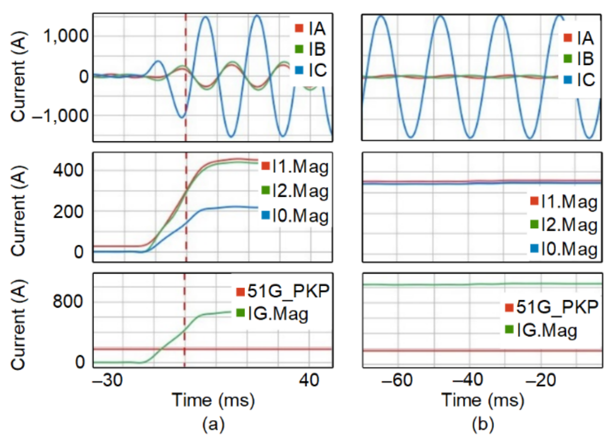

Fig. 8. Feeder relay event record for a fault between a feeder and a recloser before the recloser trips (a) and after the recloser trips (b).

The topology of this feeder is similar to the example feeder in Fig. 4, only with motor loads connected to the grounding bank's delta secondary. These can be modeled as a large impedance connected from the common bus to the transformer delta-side connections in the positive- and negative-sequence networks, as demonstrated in [9]. In most practical analyses and in the case of the Co-op's experiences, the impedances are large enough and, therefore, the currents flowing through them are small enough that they can be ignored. The model presented in Fig. 5 is a close enough approximation to satisfactorily explain what was observed and to pursue solutions.

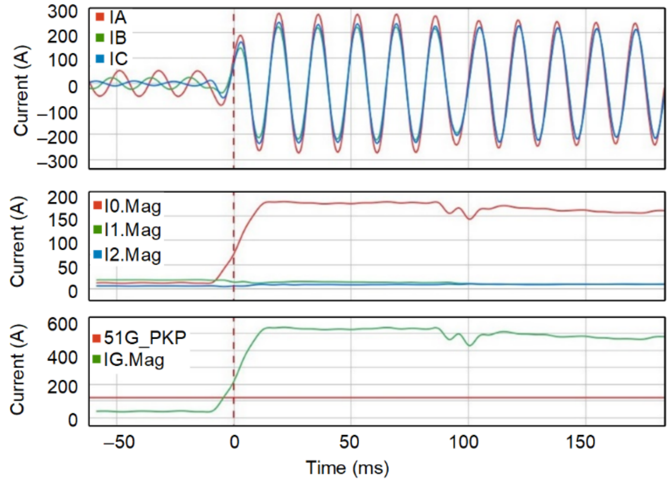

Fig. 9. Recloser control event record showing nearly pure I0 current.

V. Solutions

There are two solutions that are classically applied to secure distribution protection from undesired operation for upstream faults in the presence of a grounding bank contribution. One solution is to simply raise the pickup of the elements that trip on the grounding bank contribution. A more comprehensive solution is to apply directional overcurrent supervision to the elements that trip on the grounding bank contribution. This paper also introduces a simple current-only solution that takes advantage of the expected relationships of symmetrical component quantities to supervise overcurrent elements.

A. *Raise Overcurrent Pickups*

If the grounding bank contribution is small enough, it may be acceptable to simply raise the pickup of the ground and phase overcurrent elements to a value higher than the maximum contribution for upstream ground faults. Event captures from modern digital relays can help with identifying an appropriate pickup value, since they can record the contribution. Fig. 10 shows an example in which a new pickup of 200 A may be selected given the grounding bank contribution of 160 to 180 A recorded here. However, the user must still consider whether this increased pickup offers acceptable sensitivity.

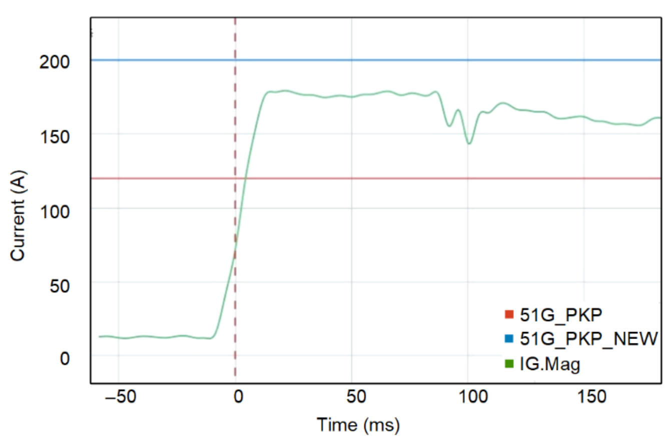

Fig. 10. A higher pickup avoids tripping on a recorded grounding bank fault contribution.

However, the user must also recognize that the grounding bank contribution can vary by fault location. A grounding bank built with smaller transformers has a higher impedance than one with larger transformers, so it provides only limited ground fault contribution, regardless of the fault location. But the grounding bank contribution in the example feeder of Fig. 6 is effectively determined as a current divider between the sum of zero-sequence impedances from the source to the fault and the sum of zero-sequence impedances from the grounding bank (inclusive) to the fault. If the impedance between the recloser and the grounding bank is much larger than the impedance from the source to the recloser, then the ratio of the current divider does not change much with fault locations upstream of the recloser. But if the recloser is closer to the grounding bank and further from the source, there can be a wide variation in grounding bank contribution, depending on the location of the fault between the source and the recloser. Raising the pickup is a simple solution, but some effort must be put into assessing whether the resulting settings secure against tripping on the grounding bank contribution for all fault locations while still providing adequate sensitivity.

B. *Directional Overcurrent Supervision*

Since the fault current contribution through the grounding bank is purely zero-sequence current, a classical ground directional element (67N) is a tried-and-true solution to determine whether the ground current observed by a recloser control or feeder relay is in the forward (tripping) direction or reverse (restraining) direction. For a ground fault in either direction, the recloser should observe a similar voltage dip on the faulted phase, making the phasor sum of the phase voltages (3V0 = VA + VB + VC) a reliable polarizing quantity to which the angle of the ground current (IG = 3I0 = IA + IB + IC) can be compared. Fig. 11 and Fig. 12 illustrate the angular relationship between I0 and V0 (referenced to the faulted phase) for upstream and downstream faults recorded by the Co-op's recloser control. The example feeder from Fig. 5 illustrates the position of these faults relative to the recloser and the grounding bank. Reference [10] is an excellent resource for the reader to learn more about directional overcurrent element design, and [11] shows examples of 3V0-polarized ground directional elements applied to pure zero-sequence fault current contributions.

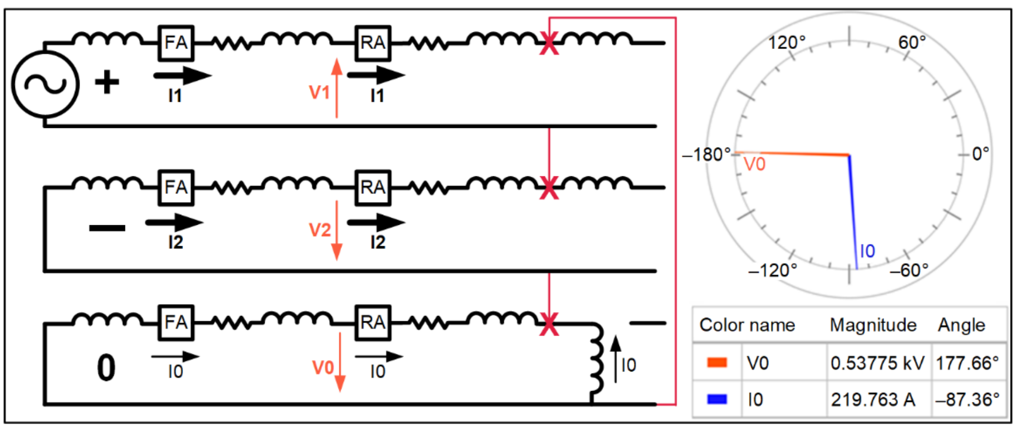

Fig. 11. Forward (downstream) single-line-to-ground fault observed by recloser control.

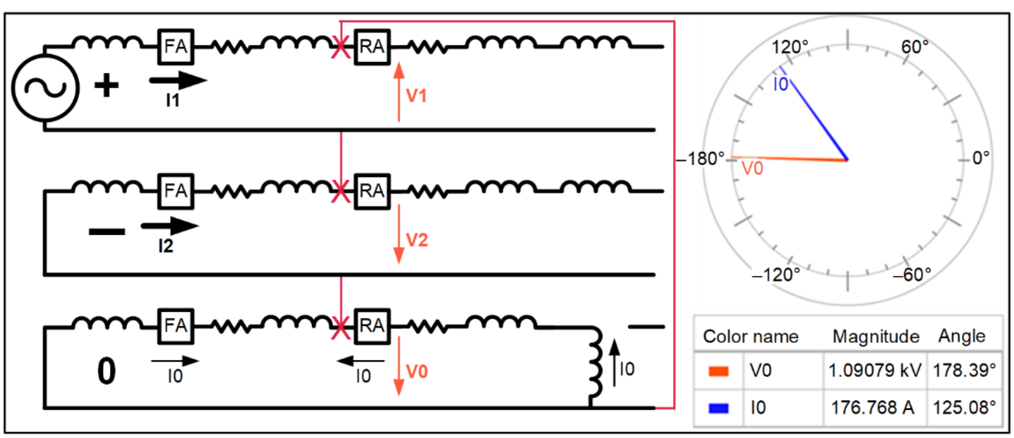

Fig. 12. Reverse (upstream) single-line-to-ground fault observed by recloser control.

C. 50Q Supervision of Overcurrent

In Fig. 11, it is evident that forward faults observed by the recloser control contain I1, I2, and I0 components. In Fig. 12, however, it is evident that reverse faults observed by the recloser control at RA contain only I0. If the grounding bank is also serving load, there are small amounts of I1 and I2 observed by the recloser control for reverse faults but, as evidenced by Fig. 9, these are insignificant compared to the zero-sequence component. The relationship between the magnitudes of these components can also be used to detect fault direction in a radial feeder with a grounding bank on the feeder. Such a solution requires no polarizing voltages and can, therefore, be applied with existing instrumentation. A current-based solution means that legacy reclosers without voltage sensors do not need to be replaced and no new transformers need to be installed.

The concept of using negative-sequence current to determine the nature of zero-sequence current is not entirely new. Reference [11] describes the use of a ratio of I0 and I2 to determine whether fault current contribution is almost purely I0 and, therefore, a V0-polarized 67N should be used. Reference [12] describes the use of a nondirectional negative-sequence overcurrent (50Q) to supervise a 67N applied to protect a mutually coupled transmission line. An ideal solution to secure distribution protection against tripping for grounding bank backfeed must be simple to apply using commonly available feeder relays and recloser controls, and it must be simple to set without the use of complex modeling or analysis.

Most modern digital relays and recloser controls offer the inclusion of a 50Q element and some user-programmable logic, at least. The 51G elements normally set by a utility can be supervised by a 50Q element so that they are only permitted to operate for forward faults when the 50Q element is picked up, as shown in Fig. 13. This introduces the question of how the 50Q element should be set and which pickup level is appropriate. Fig. 11 shows us that for forward faults with a grounding bank downstream, we can expect the recloser control at RA to measure more I2 than I0. Fig. 8 confirms this assertion with real fault data. Given this knowledge, the supervising 50Q (responding to 3I2) element can be set with a pickup equal to the 51G (responding to 3I0) minimum pickup, allowing it to supervise the 51G with no loss of sensitivity or dependability. Such a setting is well above I2 current observed, due to downstream load during an upstream fault, as evidenced in Fig. 9 and Fig. 11, so that this supervision can be made with no risk to security. For completeness, Fig. 14 and Fig. 15 show an example analysis of double-line-to-ground faults in which the recloser control at RA still measures I2 greater than I0 during forward faults and little to no I2 during reverse faults.

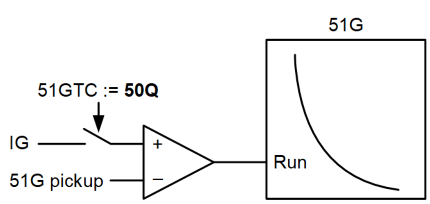

Fig. 13. 51G supervised by 50Q using torque control in a digital relay.

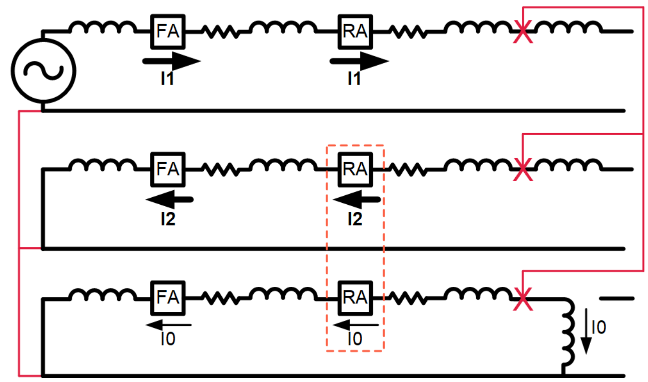

Fig. 14. Forward (downstream) double-line-to-ground fault observed by recloser control.

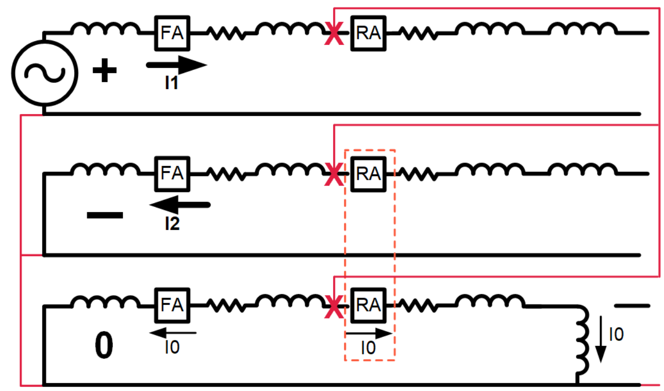

Fig. 15. Reverse (upstream) double-line-to-ground fault observed by recloser control.

It is possible for grounding bank backfeed to exceed the pickup of a phase time overcurrent (51P) element as well. A similar concept can be applied to supervise 51P, but additional care must be taken since a forward three-phase fault for which the 51P should time and trip is also devoid of I2. Consider the feeder example of Fig. 5:

- For any forward ground fault downstream for which we want to permit 51P to run, we should observe that I2 is greater than I0, according to Fig. 11 and Fig. 14.
- For any forward phase-to-phase fault downstream, we should observe that I2 is equal or greater than that observed during a ground fault at the same location.
- For any reverse unbalanced fault, we should observe almost no I2, according to Fig. 12 and Fig. 15.

We can, therefore, permit 51P to run when 50Q, already set equal to the 51G pickup, is asserted. But this only covers unbalanced fault cases. If there is a three-phase fault, there is little to no I2, but there is also little to no I0. Therefore, a simple ground overcurrent element (50G), set equal to the 51G pickup, can be used together with the 50Q element to permit 51P to operate for downstream balanced faults. 51P is also allowed to operate for upstream balanced faults, but for this condition on a radial circuit, there is no fault contribution that passes through the recloser or breaker location in question. Fig. 16 shows the combination of 50G and 50Q applied to supervise a 51P element.

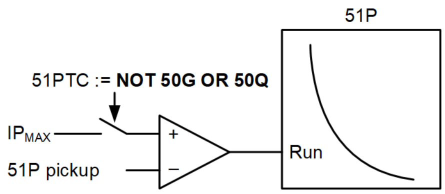

Fig. 16. 51P supervised by 50G and 50Q using torque control in a digital relay.

VI. Laboratory and Field Performance of Proposed Supervision

The idea presented in Section V, Subsection C is simple, but still, nothing works until it has been tested. Fig. 17 and Fig. 18 show results from a test relay in which the proposed logic was implemented while the recorded faults were played back to the relay. In Fig. 17, we can see that the proposed logic successfully restrains 51G and 51P for the upstream fault condition. In Fig. 18, we can see that with the proposed logic implemented, there is no loss of dependability for downstream fault coverage as 51G and 51P both pick up once 50Q asserts.

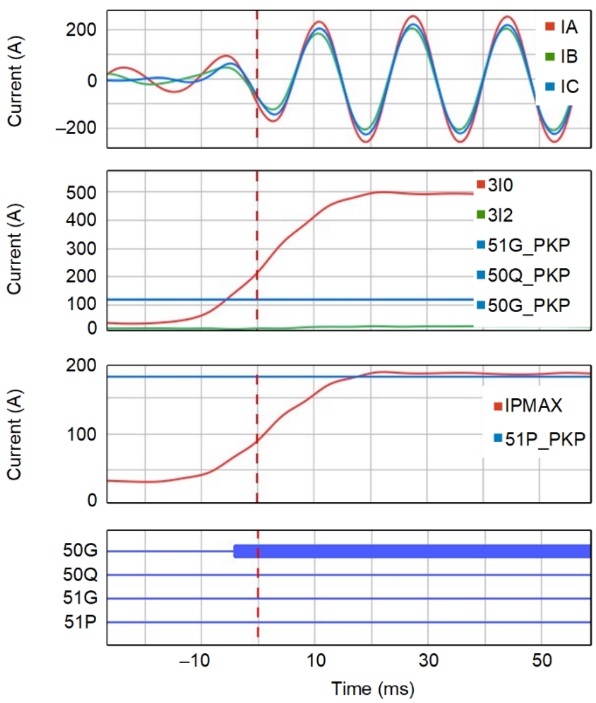

Fig. 17. Proposed logic restrains 51G and 51P for a reverse fault.

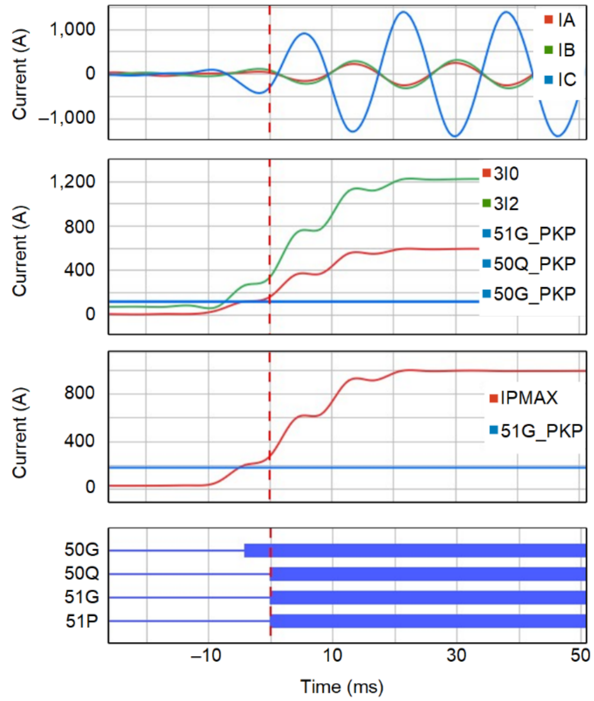

Fig. 18. Proposed logic permits 51G and 51P for a forward fault.

Laboratory testing of a solution is necessary and gives us confidence that this method will work well in the field. But nothing provides this confidence more than an actual recording of the proposed logic working properly. At the time of the writing of this paper, the recloser control to which the proposed logic was applied in the field has recorded one instance in which the logic successfully prevented a trip for an upstream fault sourced by the grounding bank downstream. This is shown in Fig. 19. In this event, an initial rise in 3I2 permits 51G and 51P to pick up momentarily. 51P drops out as the phase current magnitudes settle. As 3I2 decays, 50Q also drops out, which then prevents 51G from timing any further. While 50G was not necessary to block 51P in this instance, we do see that it picks up after a 2-cycle delay, imposed as a minimum delay for 50G elements in the relay used here. The initial rise in 3I2 is likely the result of the consumer's induction motor transient response to the fault. As shown in Fig. 19, this condition is short-lived and does not effectively threaten the performance of the proposed logic.

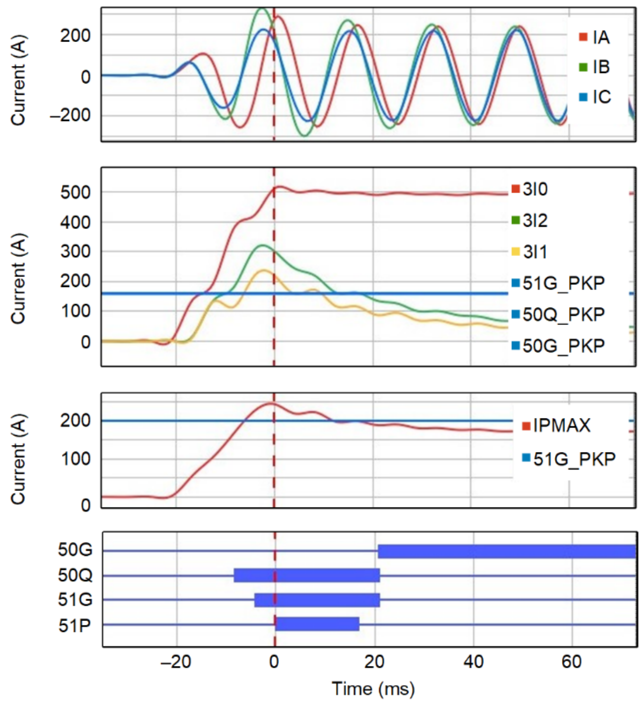

Fig. 19. Field event record of 51G restrained for a reverse fault.

VII. Limitations of Applicability

Perhaps the biggest advantage of the proposed solution is its simplicity. But it is important to also recognize the limitations of such a simple solution. All of the analysis presented in this paper centers around a radial distribution system with negligible load attached to a grounding bank on the feeder. However, distribution systems can be more complex than this, and when they are, we must carefully consider the conditions that the present analysis does not address.

A. Looped Feeders

Probably the most obvious condition in which the proposed solution does not work is in a looped power system. The premise of the proposed solution is that there is but one V1 source to the feeder, so protective devices on the feeder observe only the I0 contribution to faults upstream. Fig. 19 demonstrates the presence of ample I2 with a V1 source behind the grounding bank. The figure also shows that when the V1 source is transient, such as an induction motor load, the I2 contribution is short-lived enough that the proposed solution can still be applied. But if the V1 source were a steady-state source, like another distribution substation, ground faults in any direction would contain enough I2 for the fault duration that the proposed solution could not be applied. Nor would the philosophy be appropriate for tripping only forward faults, as protection devices must isolate the fault from both sources in a looped distribution system. For the case of looped distribution systems, a traditional V0- or V2-polarized 67N supervising forward and reverse 51 elements are the most appropriate.

B. Feeders With DERs

In some cases, the grounding bank may be applied at a DER site. Reference [13] gives an analysis of DER source impedances compared to typical distribution feeder source impedances. Inverter-based resources (IBRs) applied as DERs present a very weak source compared to typical distribution feeder sources and, as such, are known to contribute very little fault current compared to a feeder's substation source. Additionally, IBRs classically contribute a smaller ratio of I2 to I1 (compared to traditional rotating machinery sources) for unbalanced faults, as shown in [14]. In many practical cases where DERs are attached to a distribution feeder, the I2 contribution of the DER to upstream faults is still likely small enough to apply the proposed solution to restrain feeder protection, allowing the PCC protection to trip to isolate the DER from the faulted feeder.

The I2 contribution from IBRs, however, is not predictable using simple faulted circuit modeling techniques, as it depends on dynamic power electronic switching algorithms that can vary from manufacturer to manufacturer. To apply enough margin to avoid the need for complex modeling, [15] recognizes that even under fault conditions the maximum phase current contribution is typically no more than 1.3 per unit (pu) of the IBRs rated output, resulting in 3I2 contributions theoretically no higher than $\sqrt{3} \bullet 1.3 = 2.25$ pu. The modeling in [15] generated 3I2 contributions from 0.65 to 2.15 pu. The solution proposed in Section V, Subsection C can still be implemented using a 50Q pickup set higher than the DER potential 3I2 fault contribution at 2.25 pu of the IBRs rated output. In fact, such a solution may reduce the sensitivity of the 51G element, depending on the desired sensitivity and the size of the DER. If the resulting sensitivity is not acceptable, a traditional V0-polarized 67N can be used. A V2-polarized 67N may not provide reliable detection of fault current direction near IBRs [14] [15].

A DER connected to the delta winding of a grounding bank can also be a synchronous machine. In such a case, the solution proposed in Section V, Subsection C is likely not a good solution. The steady-state fault contribution of a synchronous generator may be even less than its rated output. However, the transient and subtransient fault contributions may be significant and can last long enough to operate a 51P or 51G that is permitted to run for that duration. If the synchronous machine were small enough, the supervising 50Q pickup could be set high enough to differentiate between forward and reverse faults. But this would require modeling for multiple fault locations, and the additional engineering expense would likely outweigh the cost of upgrading distribution protection so that traditional 67N and directional phase overcurrent (67P) could be employed.

C. Double-Line-to-Ground Faults Close to a Distribution Substation

Fig. 14 shows that for a downstream double-line-to-ground fault, the fault current observed by the recloser contains more I2 than I0. This assertion is made because some of the I0 is diverted around the recloser by the grounding bank, while the recloser observes the entire I2. But since the zero-sequence impedance (Z0) and negative-sequence impedance (Z2) networks are connected in parallel for a double-line-to-ground fault, this assertion also depends on the assumption that the total I0 is less than or equal to the total I2. For most faults in the distribution system, this assumption is valid, as the feeder Z0 is typically two to six times the feeder Z2 [16].

However, if a fault is close enough to the distribution substation, there is very little feeder impedance to influence the ratio of Z0 to Z2. Where the distribution system is sourced by a delta-grounded wye transformer (as is typical in North America), only the transformer's Z0 is included in the source impedance of the Z0 network. However, the Z1 and Z2 source impedances include impedances from the transformer and from the transmission system. Further, three-leg core-constructed transformers, in which Z0 is less than Z2 [16], are ubiquitous as distribution substation transformer applications. In this case, the Z0 source impedance may be less than the Z2 source impedance. If the grounding bank is far enough away, the feeder impedance may limit the grounding bank's share of the observed I0, and it is possible that I2 is actually less than I0, as illustrated in the generalized diagram of Fig. 20.

For close-in faults then, the solution proposed in Section V, Subsection C may actually reduce the sensitivity of the 51G and 51P elements. However, for close-in faults, even if I2 is less than I0, the 3I2 that is present is typically high enough to well exceed the 50Q pickup set equal to 51G, as 51G is set for sensitive and dependable fault detection to the end of the protective zone. This potential behavior then is demonstrable, but not of practical concern.

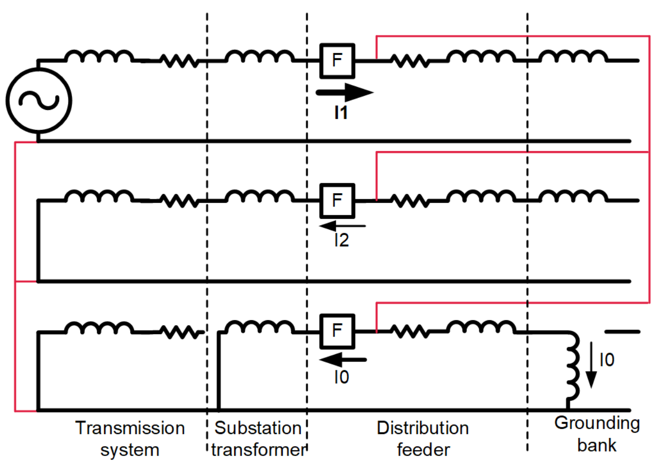

Fig. 20. Sequence currents observed for a close-in double-line-to-ground feeder fault with a grounding bank.

VIII. Conclusion

Following the unexpected trip of a recloser for feeder faults occurring upstream of the recloser, the Co-op sought to understand what was causing the recloser to trip and to establish a simple solution to secure against this tripping. This paper is the result of this study and explains why grounding banks exist on distribution systems, how they contribute fault current, and what protection devices see when observing a grounding bank fault contribution compared to a feeder source fault current contribution.

The paper offers practical solutions to secure against tripping on grounding bank backfeed for out-of-zone faults. These solutions include a novel method for supervising 51G and 51P elements using 50Q, 50G, and simple logic and guidance for setting the 50Q and 50G pickups. The new method can be applied to feeder relays and recloser controls without voltage measurement, and it is applicable to radial distribution feeders and feeders with low penetration of DERs. For looped distribution feeders or for feeders with large DERs, the traditional 67N is still a better solution.

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X. Biographies

Jeremy Blair, PE, joined Schweitzer Engineering Laboratories, Inc. (SEL) as an application engineer in 2013, authoring conference papers, application guides, and assisting customers with metering, relay, and distribution automation solutions. Previously, he worked for Entergy Corporation as a distribution planning engineer with responsibilities in distribution system planning, protection, power quality, and automation. He also managed Entergy's Automatic Load Transfer and Sectionalization Program over its four-state territory. Jeremy earned his BSEE from Louisiana Tech University and his MSECE from Georgia Institute of Technology.

Richie Matson, PE, is a licensed professional engineer with ten years of experience in electric power distribution system design, operation, maintenance, long-range and short-range planning, arc-flash hazard assessments, overcurrent protection, and substations. His primary role at Southern Pine Electric Cooperative is system planning and system protection. He also has experience in the manufacturing of high-voltage circuit breakers, high-voltage design verification testing in accordance with ANSI and IEC, and commissioning controlled switching devices utilized on high-voltage circuit breakers for energizing capacitor banks, reactors, and transformers in transmission substations. Richie is an active member of the Engineering & Operations Council with Electric Cooperatives of Mississippi, an inaugural member of the steering committee for the new annual Mississippi State University Electric Power and Meter School, and an active member of NRECA's T&D Engineering Committee and System Planning Subcommittee. Richie earned his BSEE from Mississippi State University.

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