METHODS FOR DETECTING GROUND FAULTS IN MEDIUM-VOLTAGE DISTRIBUTION POWER SYSTEMS

WHITE PAPER

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ABSTRACT

This paper reviews ground fault protection and detection methods for distribution systems. First, we briefly review and compare medium-voltage distribution system grounding methods. Next, we analyze the behavior of the different grounded systems when a ground fault occurs on these systems. We then discuss the different methods that could be used to detect ground faults on these systems. We conclude by summarizing the difference between the different grounded systems, the means to detecting faults on these systems, and the limitation of the different proposed methods.

INTRODUCTION

Ground fault current magnitudes depend on the system grounding method and fault resistance. Solidly and low-impedance-grounded systems produce high fault currents for low-resistance faults. The high magnitude of the currents requires that the line be isolated to extinguish the fault. High-resistance faults on multigrounded power systems pose the greatest challenge to conventional protective devices. The fault current generated under these conditions is relatively low and blends in with the standing unbalanced current of the power system generated because of unbalanced loads or asymmetry of the power lines.

High-impedance-grounded systems are grounded through a resistor or reactor that has an impedance equal to or slightly less than the system's capacitive reactance to ground. The fault currents for single-line-to-ground faults on these systems are rather low, and the system can still operate during fault conditions.

Ungrounded power systems have no intentional ground connection. Single-line-to-ground faults have no metallic return path and return to the system via the distributed line-to-ground capacitance. Fault currents are rather low under single-line-to-ground fault conditions.

Resonant-grounded or compensated power systems are grounded by a tuned reactor that is connected to the neutral of the transformer. The reactor is tuned so that it matches the phase-to-ground capacitance of the power system. Resonant grounding provides self-extinction of ground faults. Resonant-grounded faults are only used in overhead line applications and not in cables. The insulation medium for overhead lines is air. When the fault/arc is extinguished, the ionized air is replaced by nonionized air and the insulation integrity is restored. The same is not true for cables.

GROUNDING METHODS OF MEDIUM-VOLTAGE DISTRIBUTION NETWORKS

The main goals of system grounding are to minimize voltage and thermal stresses on equipment, provide personnel safety, reduce communications system interference, and assist in rapid detection and elimination of ground faults.

With the exception of minimizing voltage stress, operating a system as ungrounded, high-impedance-grounded, or resonant-grounded restricts ground fault current magnitudes and achieves most of the goals listed above. The drawback of these grounding methods is that they create fault detection (protection) sensitivity problems. We can create a system grounding that reduces voltage stress at the cost of large fault current magnitudes. However, in such a system, the faulted circuit must be de-energized immediately to avoid thermal stress, communications channel interference, and human safety hazards. The disadvantage is that service must be interrupted even for temporary faults.

The following is a brief description of the grounding methods typically used in medium-voltage distribution circuits.

Solidly Grounded Distribution Systems

This practice is popular in the United States. To be classified as solidly grounded, the system must have $(X_0 / X_1) \leq 3$ and $(R_0 / X_1) \leq 1$, where X_0 and R_0 are the zero-sequence reactance and resistance, and X_1 is the positive-sequence reactance of the power system. In practice, solidly grounded systems have all power system neutrals connected to ground without any intentional impedance between the neutral point and ground.

There are two different practical implementations of solid grounding in medium-voltage distribution systems: unigrounded and multigrounded. In unigrounded systems there may only be three wires with all loads connected phase-to-phase (see Figure 1), or there may be four wires with an isolated neutral and all loads connected phase-to-neutral (see Figure 2).

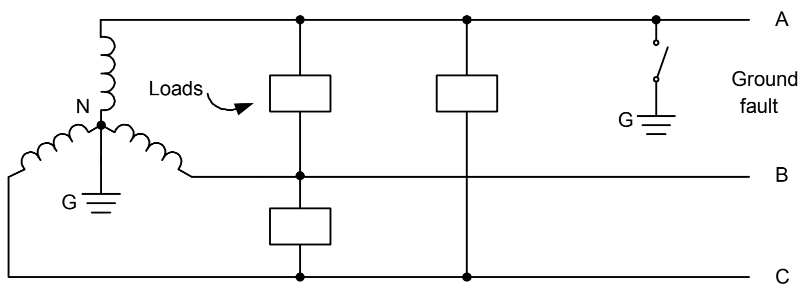

Figure 1 Solidly Grounded Three-Wire Unigrounded System

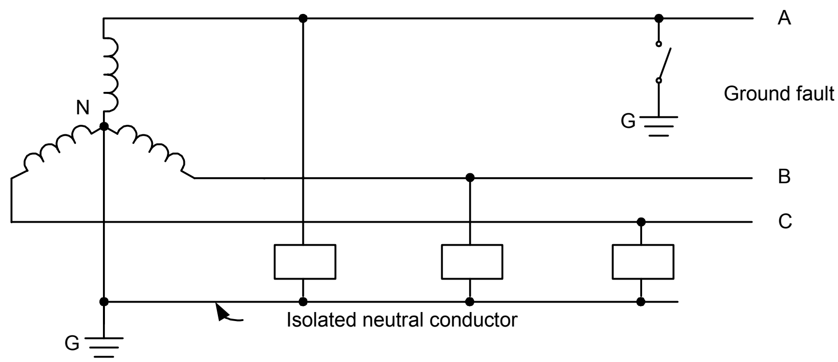

Figure 2 Solidly Grounded Four-Wire Unigrounded System

Ground faults on these systems with low fault resistance produce high-magnitude currents that require tripping the entire circuit and interrupting load to many customers. About 80 percent of ground faults occurring on overhead distribution lines are transient. For these systems, automatic multiple-shot reclosing is widely used. The resulting interruption/restoration cycle can present a problem to customers with large rotating loads or to those with loads intolerant of voltage sags.

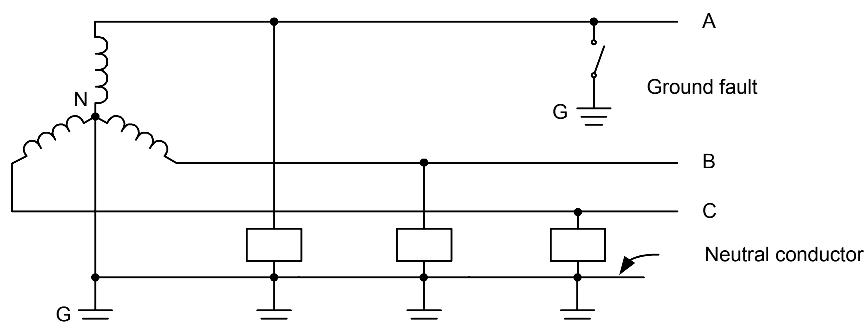

Figure 3 Solidly Grounded Four-Wire Multigrounded System

Solid grounding reduces the risk of overvoltages during ground faults. These faults do not shift the system neutral (Figure 4b). Thus the system does not require as high a voltage insulation level as does an isolated neutral system. Transmission systems are typically solidly grounded throughout the world. Unigrounded distribution systems are common in Great Britain. Multi-grounded distribution systems (Figure 3) are common in North America, Australia, and some Latin American countries.

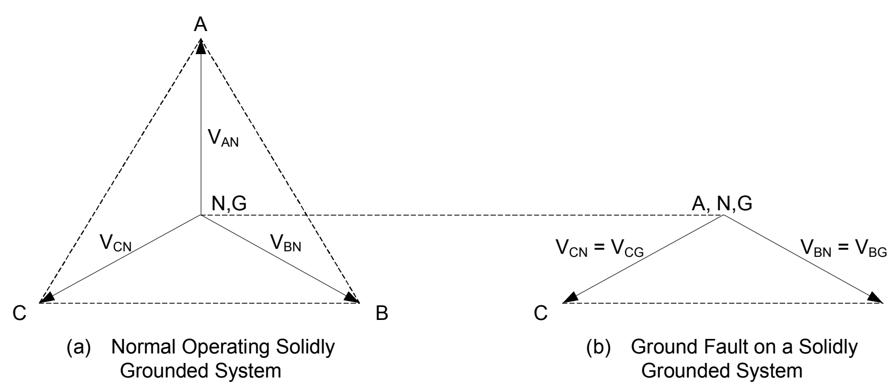

Figure 4 Phasor Diagrams

Low-Impedance Grounding

In this type of system grounding, the system is grounded through a low-impedance resistor or reactor with the objective of limiting the ground fault current. By limiting the ground fault current magnitudes to something on the order of tens or hundreds of amperes, you reduce equipment thermal stress and allow the purchase of less expensive switchgear. This method is equivalent to solid grounding in many other aspects, including ground fault protection methods.

Methods of Detecting Ground Faults in Solidly and Low-Impedance-Grounded Systems

Detecting low-resistance ground faults is accomplished by using negative- or zero-sequence quantities. Modern protective relays use the following methods to detect low-resistance ground faults.

Current Polarized Directional Element

In this element the polarizing quantity is obtained from a zero-sequence source, such as the neutral of a transformer, and the operating quantity is the zero-sequence current of the protected feeder. These operating and restraint quantities are used to calculate a torque-like product based on the magnitude of the polarizing and operating quantities and the relative angle between them. If the torque value is positive and above a threshold, a forward fault direction is declared. If the torque value is negative and below a threshold, a reverse fault direction is declared.

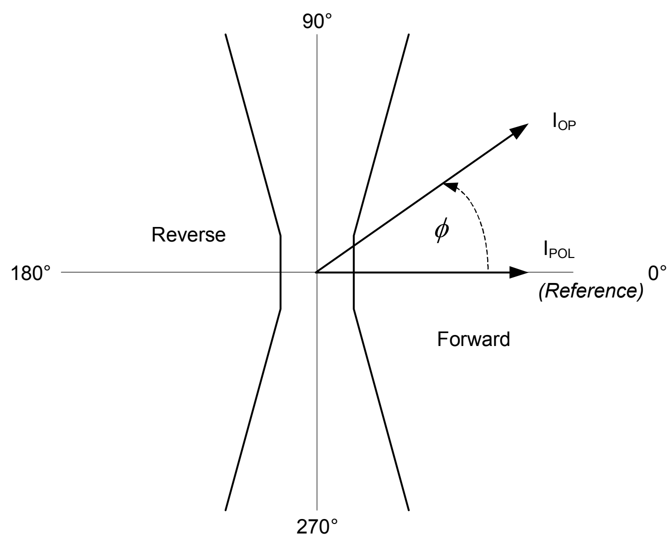

Figure 5 Current Polarized Directional Element

Negative-Sequence Voltage-Polarized Directional Element

The analog input quantities to this element are the negative-sequence voltage, V_2, and the negative-sequence current, I_2. This element calculates the negative-sequence impedance, Z_2, presented to the relay. Should this value be less than a set threshold, a forward direction is declared. Should this value be larger than a set threshold, a reverse direction is declared.

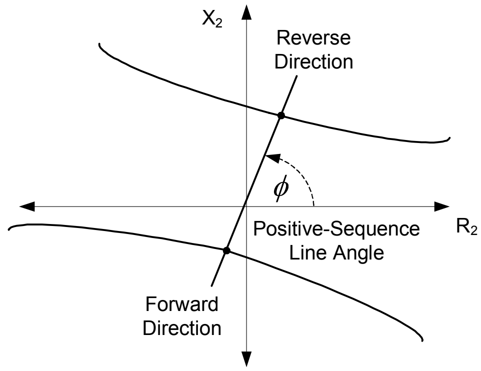

Figure 6 Negative-Sequence Impedance Plane

Zero-Sequence Voltage-Polarized Directional Element

This element is the zero-sequence analogy of the negative-sequence element. The zero-sequence voltage-polarized directional element makes directional decisions in the same way as the negative-sequence voltage-polarized directional element.

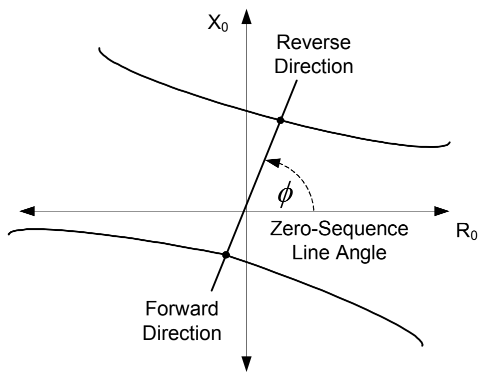

Figure 7 Zero-Sequence Impedance Plane

The relay selects the optimal directional element to run for a particular fault based on priority logic. All three directional elements have certain drawbacks. For instance, the thresholds have to be set above the maximum unbalance that the power system can experience due to normal fluctuation of the load and nonasymmetry of the conductors. In addition, these elements need to be secured during CT saturation conditions because the fictitious zero- and negative-sequence current created during this period can lead to an incorrect directional decision. Because the sensitivity of the above three elements has to be above normal load unbalance, these elements become ineffective in detecting high-resistance ground faults. These faults may produce a zero- or negative-sequence current with magnitudes less than the natural unbalance of the power system. For this reason, high-resistance ground faults require special fault-detection algorithms.

High-Impedance Fault (HIF) Detection Element

HIFs have challenged utilities and researchers for years in power distribution systems with voltages ranging from 4 kV to 34.5 kV. HIFs are those faults on distribution feeders with fault currents below traditional overcurrent relay pickups. Fallen power conductors on poorly conductive surfaces, tree branches brushing against power lines, and dirty insulators are all potential causes of HIFs. Researchers in many studies of staged HIFs on grounded distribution systems have recorded fault current magnitudes that vary anywhere from zero to less than 100 amperes.

HIFs have such low fault currents that they generally do not affect power distribution system operation. However, HIFs caused by downed power conductors are major public safety concerns. Without timely correction, these faults can be hazardous to human lives and property. There have been a number of documented cases of costly litigation as a result of damages from undetected downed power conductors.

HIFs on multigrounded distribution systems are difficult to detect at the substation level. Single-phase loads and the multipath returns of unbalanced currents contribute to the difficulty in detecting these faults. A grounded system can be very unbalanced when a major single-phase lateral is out of service. Beyond ensuring coordination with downstream devices and fuses and avoiding cold load pickup and transformer inrushes, you must avoid false tripping by setting conventional ground overcurrent protection above the maximum foreseeable unbalance. Thus overcurrent protection that uses the fundamental component or root-mean-square (rms) values of the current are ineffective in detecting HIFs. Some HIFs, such as those resulting from downed power conductors on asphalt or dry sand, generate virtually no fault current. No substation-based devices can detect these HIFs or down-conductor situations.

While it is relatively easy to design an algorithm that detects certain HIFs, it is challenging to make the algorithm secure. The objective of HIF protection is to remove hazards from the public. When an HIF detection device indicates a fault, utilities need to make tripping decisions based on a number of circumstances to ensure that the tripping won't cause more hazardous situations. Utilities cannot tolerate false alarms from HIF detection devices. It can be dangerous and costly, for example, to trip out a busy traffic intersection, hospital, or airport load.

Below are two elements that modern relays may use to detect HIFs. The first is based on counting the number of times that a sensitive residual overcurrent element picks up and drops out, and the second uses a special detection quantity and a trending analysis.

Element 1: Residual Overcurrent Counting Element

Figure 8 shows the block diagram of the residual overcurrent-counting HIF detection element. It uses a sensitively set residual overcurrent element, 50NHI, and a two-stage counting scheme to detect HIFs. The first stage counter counts the rising edges, or pickup/dropout actions, of the 50HNI element. If the number of counts reaches a set level within a time window, the first stage counter outputs a logical 1 to the next counting stage. The second stage counter repeats the same process but counts the first stage outputs and has a different pickup threshold and reset time window. When the second stage count reaches its set threshold, the detection element generates an output to light the LED, sounds an alarm, or trips a breaker. The counters of both stages are cleared in a reset window time after they start counting. Pickups of other overcurrent protection elements also reset the HIF detection element.

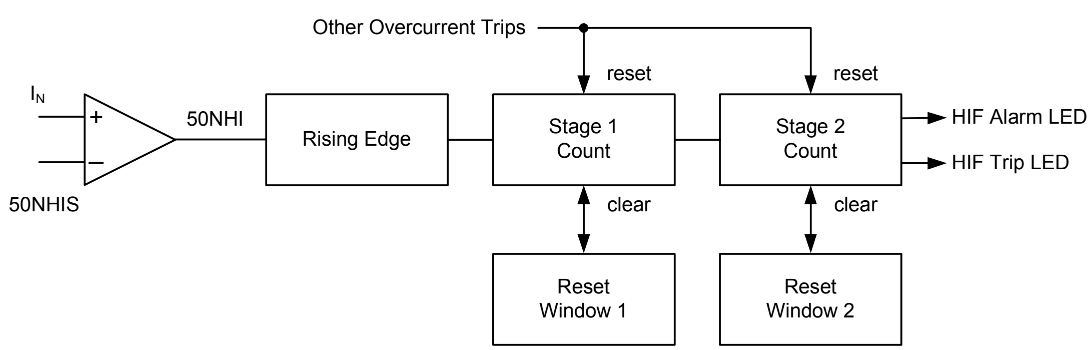

Figure 8 Block Diagram of Overcurrent Counting HIF Detection Element

Element 2: Sum of Difference Current (SDI) HIF Detection Element

Figure 9 shows the SDI HIF detection element of the A-phase current. The same processing also applies to the B-phase, C-phase, and residual currents.

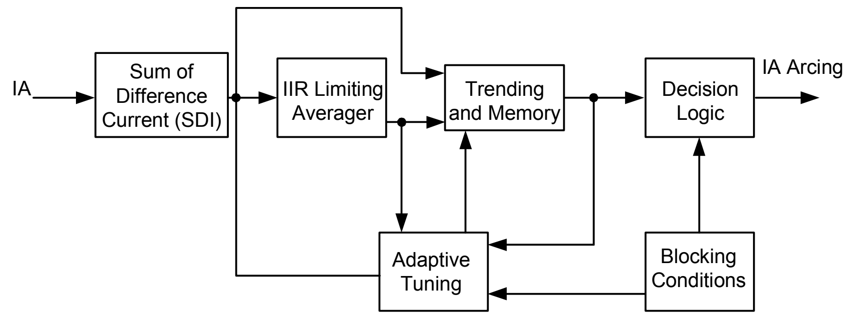

Figure 9 Block Diagram of SDI HIF Detection Element

The first function block calculates a signal quantity upon which the algorithm bases its HIF detection. This quantity is the SDI. An infinite-impulse-response (IIR) limiting averager establishes a stable reference for the SDI. The trending and memory block compares the SDI with the SDI average and memorizes the time and ratio if the SDI is a set threshold above the SDI average. The decision logic uses the results from the trending and memory block to determine the existence of an HIF on the processed phase. The adaptive tuning block monitors feeder background noise during normal system operations and establishes a comparison threshold for the trending and memory block. The IIR limiting averager also uses this threshold to prevent the averager input magnitude from becoming too large.

Because HIFs generated low current magnitudes, researchers realized at the beginning that to detect an HIF, they would have to search for signal quantities other than the rms or fundamental frequency component of currents. HIFs typically involve arcing and conduction through ground surfaces. Both arcing and soil conduction present nonlinear resistance to current flow and, therefore, generate harmonics. On the other hand, normal nonlinear loads, such as motor centers, power inverters, and arc furnaces, also generate significant harmonics, especially odd harmonics. What we want are signal quantities that mostly reveal the signatures of HIFs but vanish under normal system operation conditions.

Figure 10 shows the SDI used for the detection element. The system tracks power system frequency and samples feeder currents (I_k) at an integer number (Nspc) of samples-per-system-cycle. The system uses a simple one-cycle difference filter to calculate difference current (DI_k) and obtains SDI by accumulating the absolute value of the difference current during several power cycles (N_s).

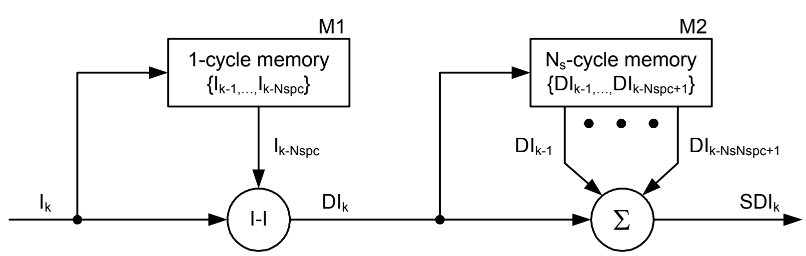

Figure 10 Calculation of SDI

Figure 11 illustrates the SDI calculation in time domain with the current waveform from an HIF sampled at 32 samples-per-cycle. For ideal sinusoidal waveforms, the one-cycle difference calculation would result in an output of all zero values. With the arcing current of an HIF, however, the one-cycle difference of the current reveals the activity of the random arcing process.

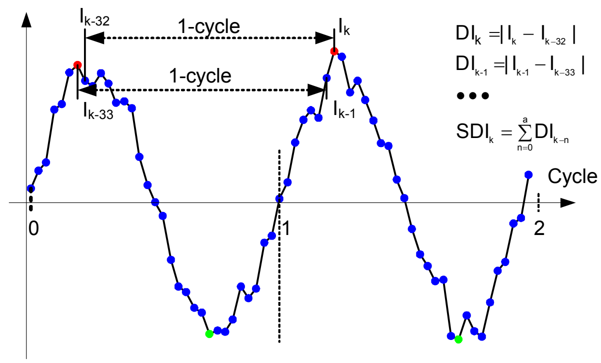

Figure 11 Time Domain Illustration of SDI Calculation

Figure 12 shows the magnitude portion of the frequency response of the one-cycle difference calculation to the fourth harmonic. Note that the magnitude response has a zero at every harmonic frequency and that this includes the dc and the fundamental frequency. All harmonic components, including the dc and the fundamental of the current, are, therefore, blocked after the difference calculation. The frequency content of the difference current contains only off harmonics. The SDI represents an average measure of the total off-harmonic content of a current over an N_s-cycle window, making SDI a valuable tool for HIF detection.

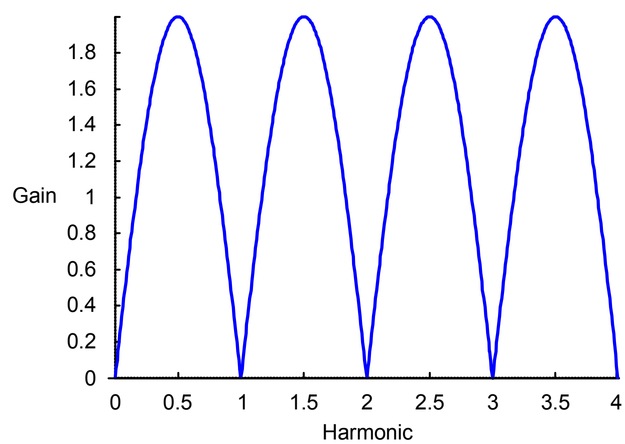

Figure 12 Frequency Magnitude Response of the One-Cycle Difference Filter

When an HIF occurs, the SDI quantity increases. The amount of increase can be appreciated only by comparing the quantity with its history. Providing a reliable reference is the function of the IIR limiting averager, and the quality of this reference is important to the success of the detection algorithm. An IIR type of averaging with a fixed time constant is used because relatively few calculations and memory units efficiently achieve long-term memory effects. You must choose a time constant large enough to provide a stable reference during faults. On the other hand, a small time constant is good for allowing rapid tracking of the input average during normal conditions. To strike a balance between these conflicting requirements and to prevent the average from rapidly following large SDI spikes, the input to the averager is limited when the SDI value is above a threshold, as shown in Figure 13. When conditions other than HIFs occur, the freeze input, RFRZ_MCLR, becomes a logical 1 and the IIR limiting average calculation is suspended. These non-HIF conditions include large changes in phase currents and changes in line voltages.

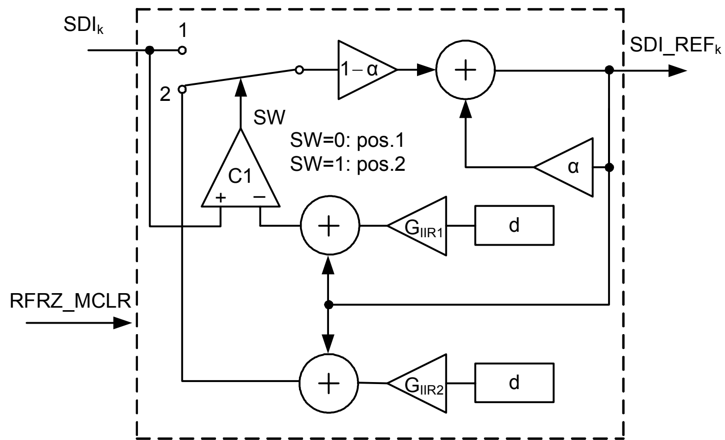

Figure 13 IIR Input Limiting Averager

Once the algorithm establishes the detection quantity, SDI and its average SDI_REF, the algorithm must extract the HIF signature from these quantities. The trending and memory function shown in Figure 14 records unusual SDI changes related to system HIFs and memorizes these changes for the decision logic. The trending and memory function provides information regarding how often and by how much the SDI exceeds the SDI_REF plus a margin.

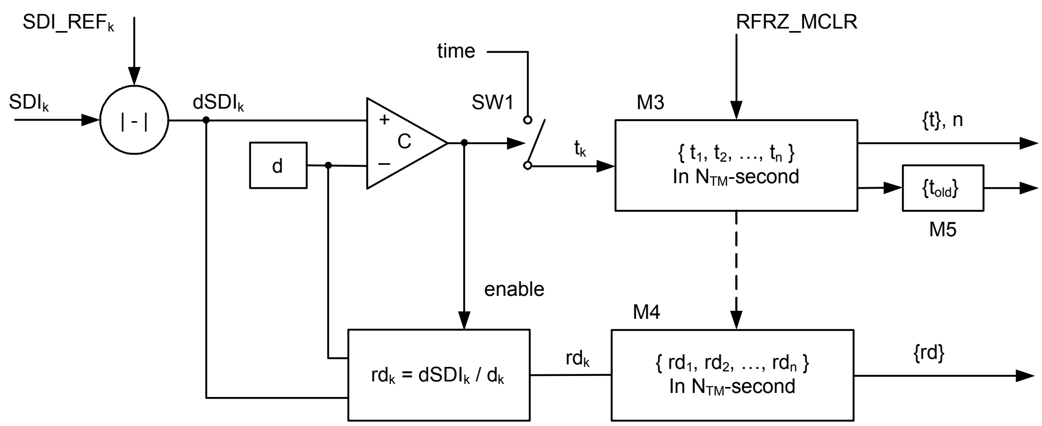

Figure 14 Trending and Memory Function

When setting traditional overcurrent relays, a short-circuit study program is used to calculate the fault current under different system operation conditions. The fault current satisfies Ohm’s law, so the settings calculation process is straightforward with known system topologies and parameters.

For HIF detection, the situation is different. HIF detection uses nontraditional quantities. Nonlinear and dynamic feeder loads influence these quantities in different ways. For example, if an HIF detection algorithm uses the fifth current harmonic, detection settings would be different for feeders with six-pole power inverters than for feeders that only have relatively quiet residential loads. Given the vast variety of distribution loads, it would be impractical for users to study the loads of each feeder and determine the effects these loads have on the detection algorithm they choose to use.

The purpose of the adaptive tuning function shown in Figure 15 is for the algorithm to automatically characterize the detection quantity of a feeder for its normal loads. The function learns a margin above the SDI average into which the SDI value may fall as a result of normal system operations. Both the IIR limiting averager and trending and memory functions use this margin, labeled as variable {d}. The enable input of Figure 15, AT_Enable, determines when the {d} update occurs. Some distribution loads, such as rail train systems, have daily cycles, and other loads, such as motor pumps for farms, have seasonal cycles. Ideally, the tuning process should be continuous as long as there are no HIFs or other events on the system. The tuning should also remain for a certain period of time after a breaker closure and load current detection.

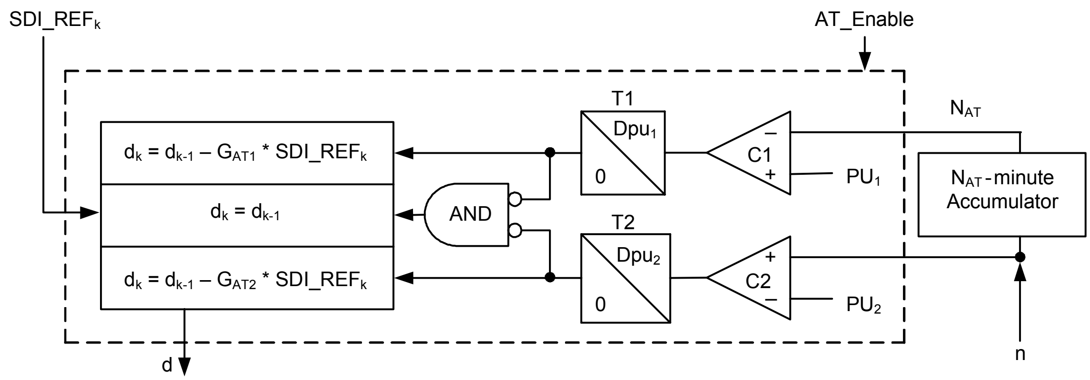

Figure 15 Adaptive Tuning Function

The trending and memory function provides valuable information regarding how often and by how much the SDI exceeds its reference plus a learned margin. The value of {n} represents the number of times the SDI exceeded its threshold within the previous N_{TM}-seconds, while the set of ratios, {rd}, represents the information concerning the amount by which the SDI exceeded its threshold. The first block of the decision logic in Figure 16 calculates a set of time differences, {dt}, through the use of the set of time {t} and $\{t_{old}\}$ from the trending and memory function. The time difference can provide the timing characteristic of randomness signature of the HIF. It is possible to use some artificial intelligence methods of classification and pattern recognition, such as neural network or decision trees, to decipher this information for the detection of HIFs. We chose, instead, to use relatively simple comparators and counters for the decision logic.

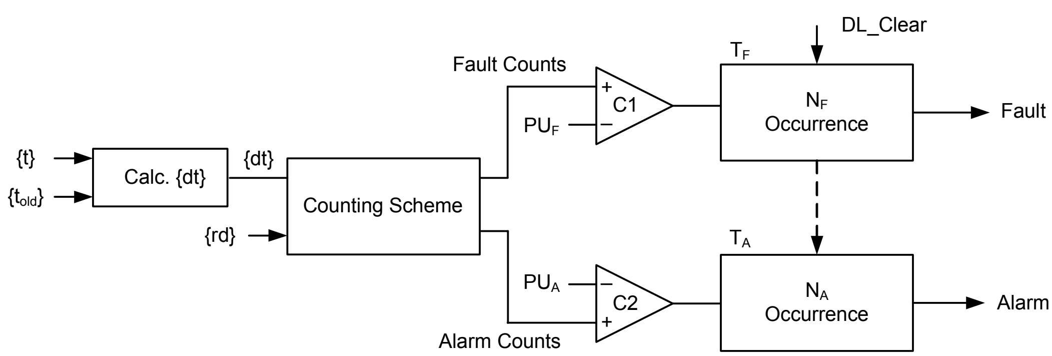

Figure 16 Block Diagram of Decision Logic

The decision logic has two counters for separate HIF alarms and trips. Counter T_F is for HIF detection, and counter T_A is for an HIF alarm. For each pair of {rd, dt} in the previous N_{TM}-second segment, a counting scheme determines whether to count or not count as well as the number of counts for a fault or alarm. For each N_{TM}-second segment, if the number of counts for an HIF exceeds PU_F as determined by comparator C1, the comparator produces a logical 1 output.

Counter T_F accumulates the number of logical 1s from comparator C1. If N_F occurrences accumulate within a fault decision time, counter T_F produces a logical 1 output to indicate detection of an HIF. The algorithm uses a similar method for deriving an alarm for an HIF through comparator C2 and counter T_A, but it uses different detection thresholds, as Figure 16 indicates.

Figure 17 shows an {rd,dt} plane. The entire plane is divided into three regions: fault count, alarm count, and no count. The {dt} axis has a unit of N_s-cycle, the interval over which SDI accumulates. If an {rd,dt} pair falls into the no count region, the algorithm generates no counts for either alarm or fault. If an {rd,dt} pair falls into the alarm count region, the algorithm generates counts only for HIF alarms. If an {rd,dt} pair falls into the fault-count region, the algorithm generates counts for both fault and alarm conditions of HIFs.

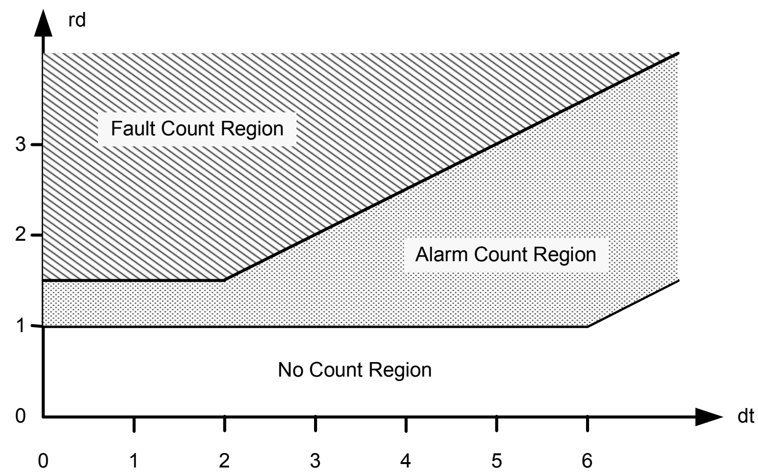

Figure 17 Counting Regions for Alarm and Fault Conditions

This counting scheme on the {rd,dt} plane is much like the percentage restraint current differential characteristic, with {dt} similar to the restraining quantity and {rd} similar to the operating quantity. Sporadic and isolated high SDI values can arise from system switching, such as turning capacitor banks on and off or moving load tap changers up and down. Such values can also result from lightning strikes during storm seasons. We can discount these SDI events because they are associated with large {dt} values. On the other hand, intense and active arcing events from HIFs tend to produce high SDI values clustered in a short period of time. Therefore, the related {rd,dt} pairs would be more likely to reside in the operating region of the counting scheme.

Figure 18 shows how the algorithm generates the number of counts as a function of the ratio {rd} for each {rd,dt} pair that the counting scheme shown in Figure 17 determines to be countable. For example, if the {rd} value in an {rd,dt} pair is four, and the pair falls into the fault count region, then the algorithm generates not one, but two fault and alarm counts for the {rd,dt} pair. Studies of staged HIF data indicate that the SDI value generally correlates to the relevance of an event to HIFs. By making the number of counts proportional to the ratio, {rd}, the algorithm considers not only the event that SDI overcomes its threshold but also the amount of SDI increase in determining the existence of a fault.

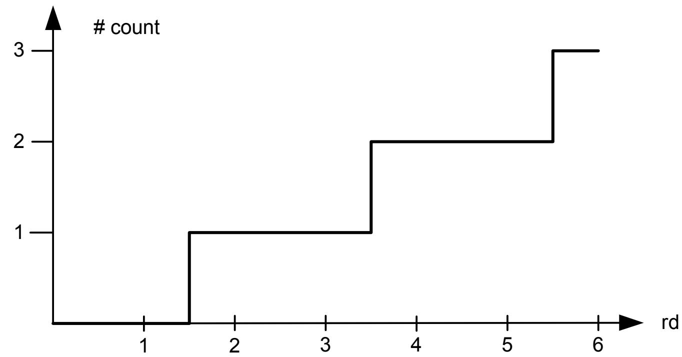

Figure 18 Number of Counts as a Function of {rd}

Several system conditions disable the decision logic as indicated by the DL_Clear input. Some of these conditions include large phase current changes and some voltage changes. The algorithm also detects and uses events that occur in all three phases to disable the decision logic because we assume that these events are highly unlikely HIFs.

High-Impedance Grounding

In this method, the system is grounded through a high-impedance resistor or reactor with impedance equal to, or slightly lower than the total system capacitive reactance to ground. The high-impedance grounding method limits ground fault current to 25 amperes or less. Of the two high-impedance methods mentioned previously, high-resistance grounding is preferred because the method limits transient overvoltages to safe values during ground faults. The grounding resistor may be connected in the neutral of a power or grounding transformer, generator, or generator grounding bus or across the broken delta of phase-to-ground-connected distribution transformers.

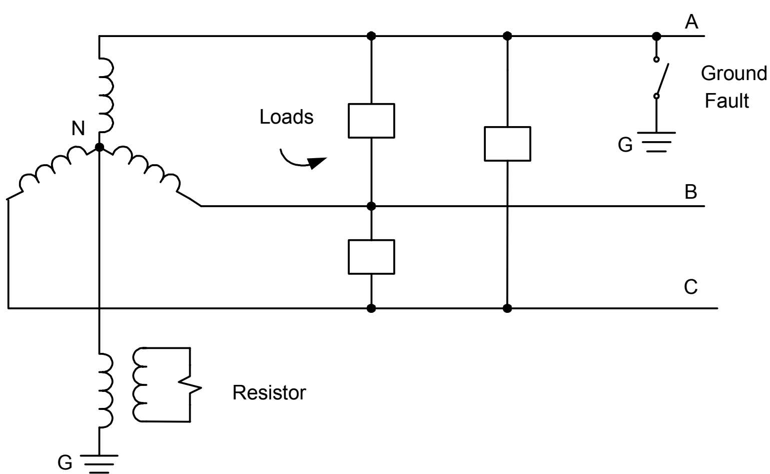

Figure 19 High-Resistance-Grounded Power System

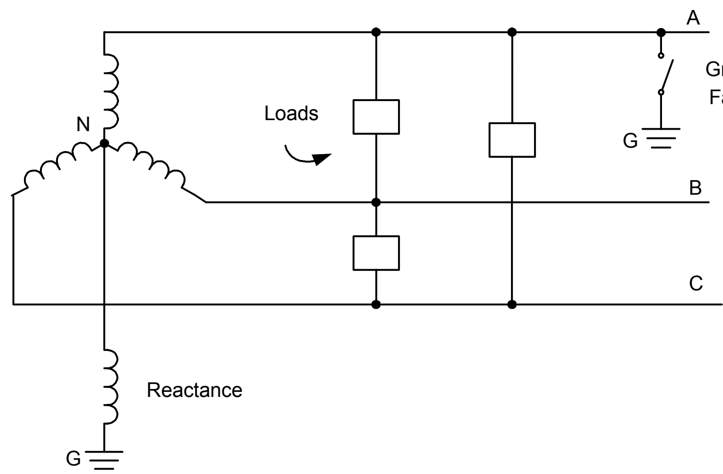

Figure 20 High-Reactance-Grounded Power System

Methods of Detecting Ground Faults in High-Impedance-Grounded Systems

In this system the loads are connected phase-to-phase similarly to ungrounded system connections. Loads are not connected phase-to-ground as is the case in solidly grounded systems. To detect line-to-ground faults on these systems, the relay uses a zero-sequence voltage-polarized directional element similar to the one employed in solid or low-impedance-grounded systems. To increase the element's sensitivity, the measured neutral or residual current is used instead of the calculated residual or neutral current. Employing a toroidal or summation current transformer enables the measurement of the neutral residual current.

The directional element calculates the zero-sequence impedance using the zero-sequence voltage and currents. The zero-sequence current is adjusted by the maximum torque angle. The adjustable maximum torque angle allows the element to be used on both high-resistance-grounded systems as well as on high-reactance-grounded systems.

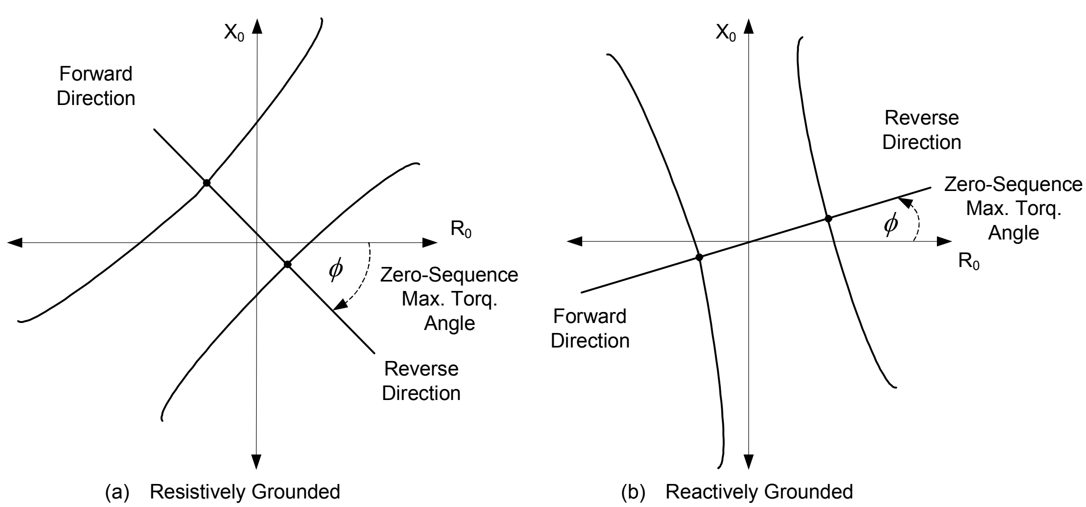

Figure 21 Zero-Sequence Impedance Planes

UNGROUNDED OR ISOLATED-NEUTRAL SYSTEMS

In an isolated-neutral system (Figure 22), the neutral has no intentional connection to ground. The system is connected to ground through the line-to-ground capacitances. Single-line-to-ground faults shift the system-neutral voltage but leave the phase-to-phase voltage triangle intact.

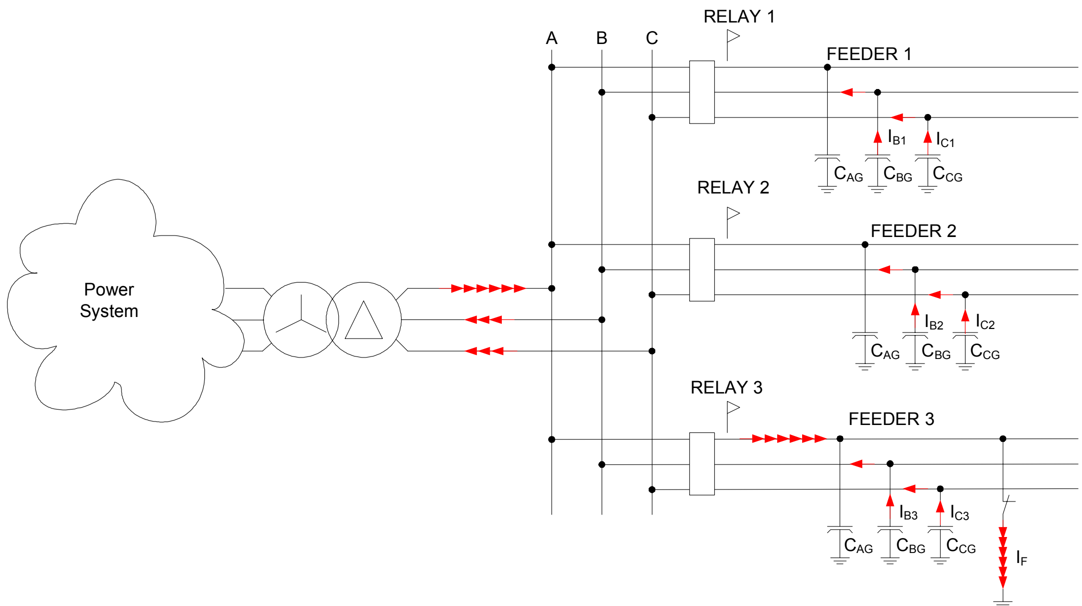

Figure 22 Ungrounded Power System With A-Phase-to-Ground Fault on Feeder 3

For these systems, two factors limit the magnitude of the ground fault current:

- Zero-sequence line-to-ground capacitance
- Fault resistance

Because the voltage triangle (Figure 23) is relatively undisturbed, these systems can remain operational during fault conditions.

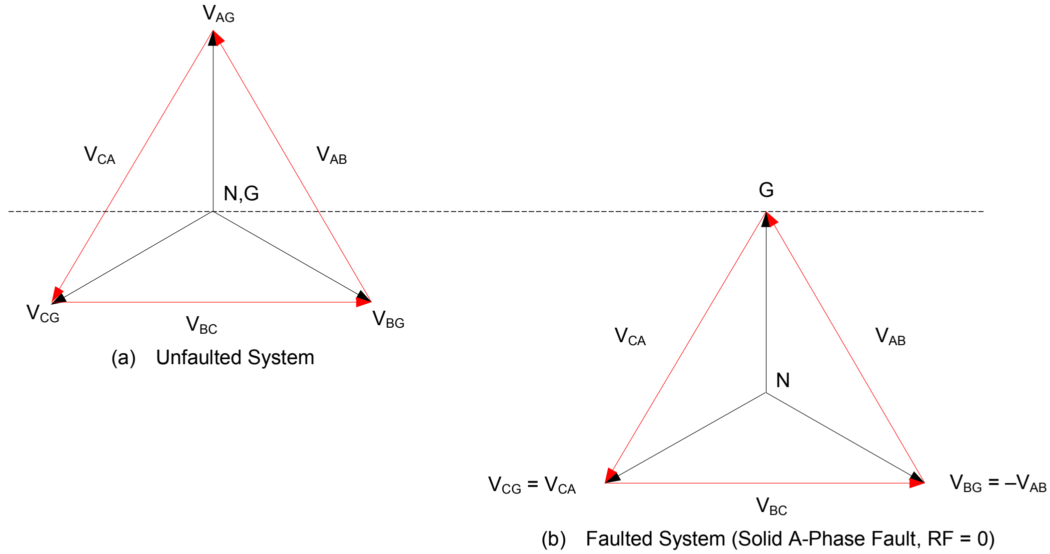

Figure 23 Voltage Phasor Diagrams for the System in Figure 22

Methods of Detecting Ground Faults in Ungrounded Systems

The zero-sequence network of an ungrounded system has a very high impedance when compared to positive- and negative-sequence network impedances. Therefore, ignoring these networks when evaluating single-line-to-ground faults does not result in significant loss of accuracy. Figures 24 and 25 show the zero-sequence networks for forward and reverse faults, respectively.

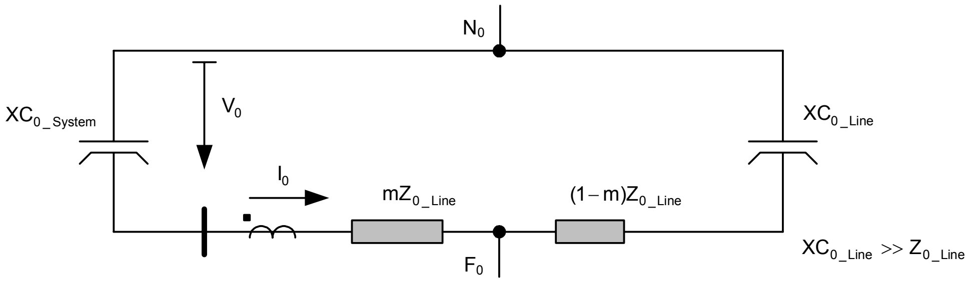

Figure 24 Zero-Sequence Diagram for a Forward Ground Fault

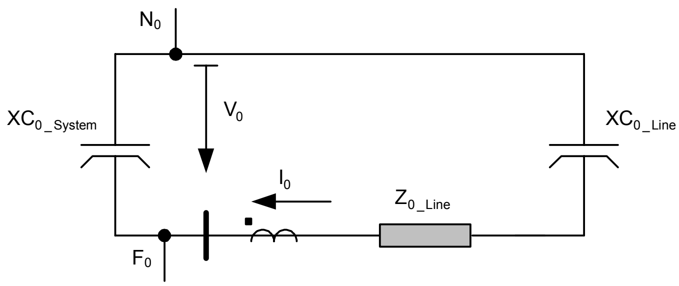

Figure 25 Zero-Sequence Diagram for a Reverse Ground Fault

Using the zero-sequence voltage, V_0, as a reference and comparing the angle of the zero-sequence current, I_0, against this reference, we can determine the directionality of a ground fault on these systems. If we examine Figure 24, we can see that for a forward fault, I_0 lags V_0 by 90°, and from Figure 25, we can see that for a reverse fault, I_0 leads V_0 by 90°. Using this information and using the same zero-sequence impedance calculation as for the solidly grounded system, we can plot the calculated zero-sequence impedance in the zero-sequence impedance plane. Notice that the characteristic is the inverse of a solidly grounded system with a zero-sequence line angle equal to 90°.

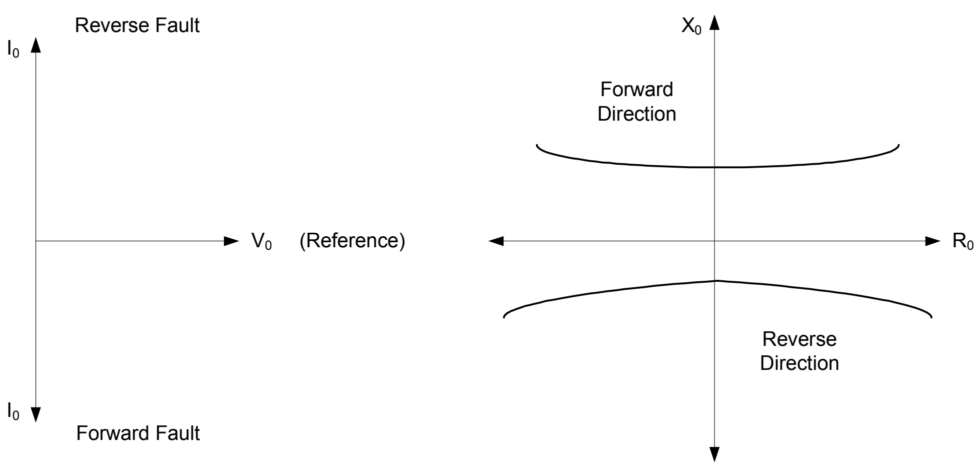

Figure 26 Zero-Sequence Impedance Plane

For solidly grounded systems, the standing zero-sequence unbalance of the power system limits the sensitivity of this element. In special cases, the ground fault could result in the power system being perfectly balanced.

Resonant Grounding

In resonant-grounded systems, the power system is grounded through an inductance with an impedance value approximately equal to line-to-ground capacitance of the power system. The high-impedance of the ground loop limits the fault current during single-line-to-ground faults. Loads are connected phase-to-phase in this system. When a single-line-to-ground fault occurs, the faulted phase-to-neutral voltage and the unfaulted phases experience a rise in voltage, but the voltage triangle does not get affected. Similar to an ungrounded system, loads can still be serviced without any adverse effects to the power system.

Methods of Detecting Ground Faults in Resonant-Grounded Systems

The high magnitude of the zero-sequence impedance compared to the positive- and negative-sequence impedances allows us to ignore the positive- and negative-sequence networks without much loss of accuracy when evaluating single-line-to-ground faults on resonantly grounded power systems. The zero-sequence used for single-line-to-ground faults in resonant-grounded systems is shown in Figure 27. For this analysis, we assume that the conductance of the power system was infinity. Stated another way, the insulators are perfect, and the system is perfectly balanced beforehand. This means that the driving voltage of the fault is the prefault line-to-neutral voltage.

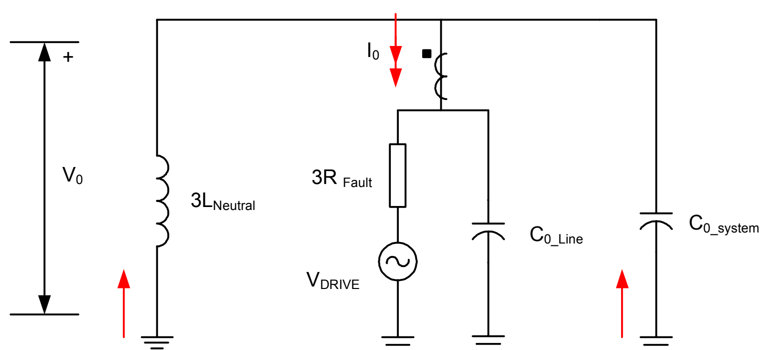

Figure 27 Zero-Sequence Network Diagram for a Forward Fault

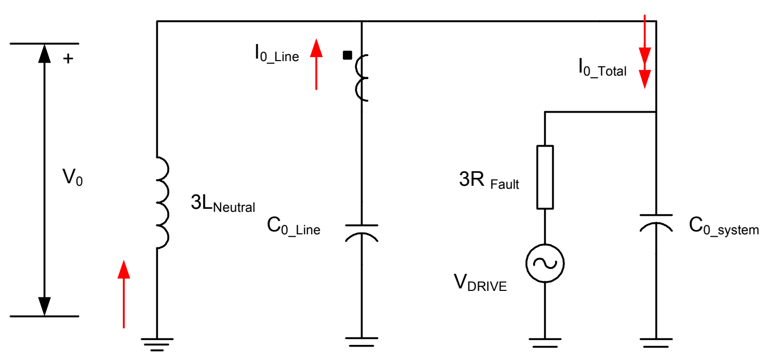

Figure 28 Zero-Sequence Network Diagram for a Reverse Fault

If we examine the zero-sequence network for a forward fault, we will see that the zero-sequence current, I_0, for a perfectly tuned system, is 180° out of phase with the zero-sequence voltage, V_0. However, most systems are generally over- or under-tuned, which simply causes the zero-sequence current to either lead the zero-sequence voltage by more than 90° or lag the zero-sequence voltage by more than –90°. If you were to calculate the torque/real power in all the above cases, you would have a negative result. By examining the zero-sequence networks for a reverse fault, we see that the zero-sequence current for a perfectly tuned system is in phase with the zero-sequence voltage. The zero-sequence current for a reverse fault on an over- or under-tuned system causes the zero-sequence current to either lead the zero-sequence voltage by less than 90°, or lag it by less than –90°. In all cases the torque, or real power, developed is positive.

Therefore, using this information, you can say that a negative power is developed for a forward fault, and a positive power is developed for a reverse fault. Therefore, if you used a wattmetric element (an element that calculates real power), you could use the following logic. If the power developed is less than a set negative threshold, the fault is forward, and if the power developed is greater than a set positive threshold, the fault is reverse. Figure 29 shows the phasor diagram for the wattmetric element.

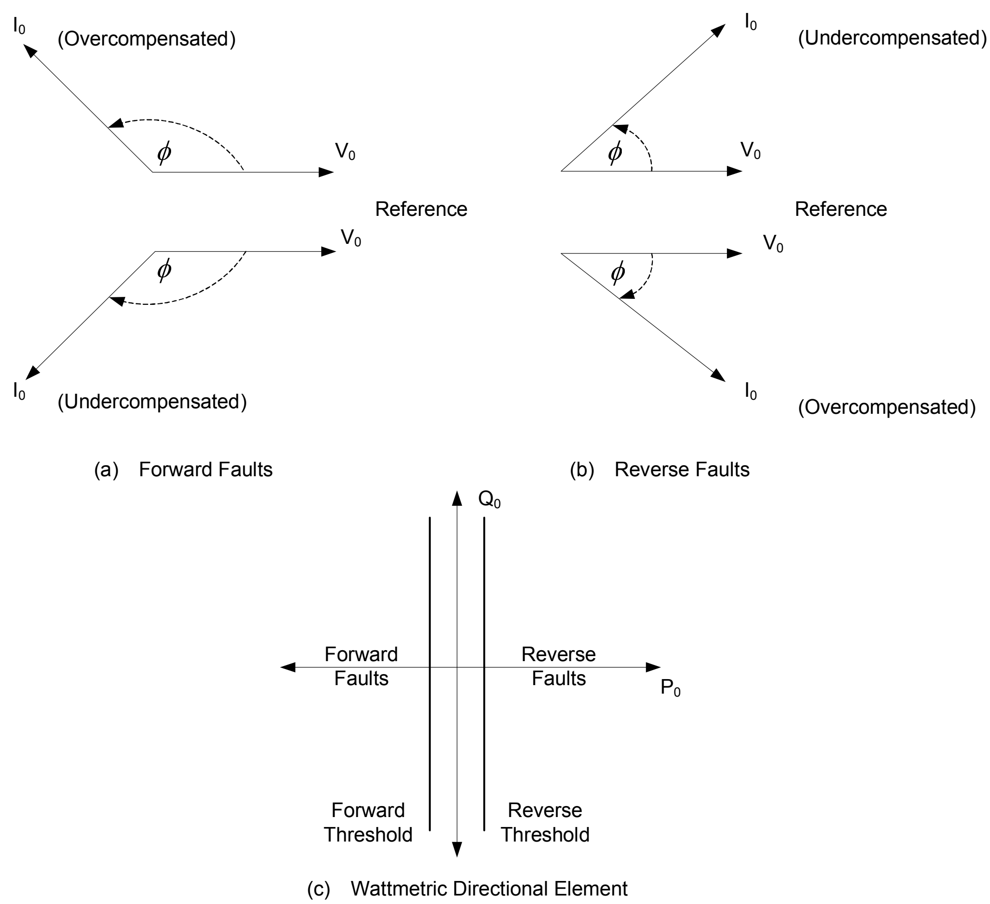

Figure 29 Phasor Diagram for the Wattmetric Element

The sensitivity of the wattmetric element is once again inhibited by the standing unbalance of the power system. However, because most utilities require fault detection for faults that may generate voltages or currents that are less than the standing unbalance of the power system, the incremental conductance method was introduced. This method simply calculates the incremental change in the conductance of the power system. To calculate the incremental conductance, divide the incremental change in current by the incremental change in voltage, where the incremental change in current is the difference between the prefault current and the fault current, and the incremental change in voltage is the difference between the prefault voltage and the fault voltage. If the calculated change in conductance is positive, the fault is forward. If the calculated change in conductance is negative, the fault is reverse.

CONCLUSION

From the above discussion, it is clear that detecting single-line-to-ground faults on medium voltage distribution systems is dependent on two important factors:

1. Type of grounding employed on the power system
2. Resistance of the fault

Also apparent from the above discussion, is that high-resistance ground faults on solidly or low-impedance-grounded power systems pose the greatest challenge to protective devices. If we were to summarize the different methods used to detect single-line-to-ground faults on medium-voltage distribution systems using grounding methods, fault current, and detection methods as criteria, we could represent it graphically as in Figure 30.

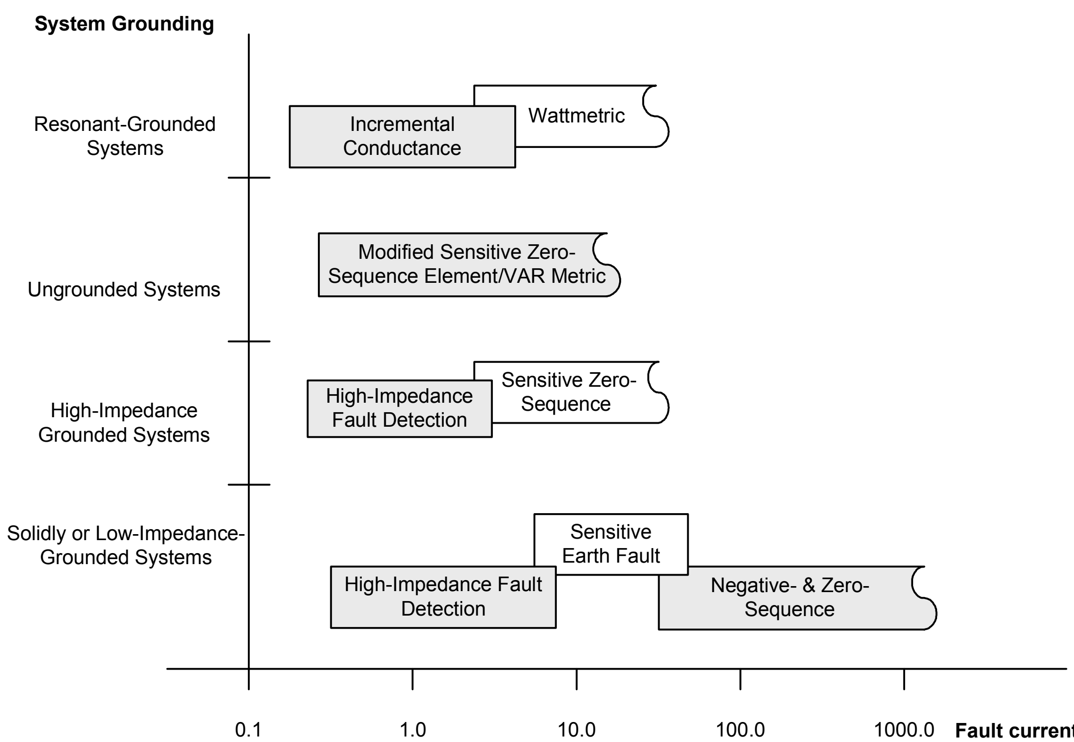

Figure 30 System Grounding and Fault Current Graph

APPENDIX

Table A1 tabulates the different grounding methods, their pros and cons, and where you would be likely to encounter these systems.

Table A1 Comparison of Grounding Methods for Medium-Voltage Distribution Networks

Issues	Grounding Method					
	Isolated Neutral	Solid Grounding (Unigrounding)	Solid Grounding (Multigrounding)	Low-Impedance Grounding	High-Impedance Grounding	Resonant Grounding
Some Countries of Application	Italy, Japan, Ireland, Russia, Peru, Spain	Great Britain	USA, Canada, Australia, Latin America	France, Spain		Northern and Eastern Europe, China, Israel
Permissible Load Connection	Phase-to-phase	Phase-to-phase (3 wires) and phase-to-neutral (4 wires)	Phase-to-phase and phase-to-ground	Phase-to-phase	Phase-to-phase	Phase-to-phase
Required Insulation Level	Phase-to-phase	Phase-to-neutral	Phase-to-neutral	Phase-to-neutral	Phase-to-phase	Phase-to-phase
Limitation of Transient Overvoltages	Bad	Good	Good	Good	Good (R-grounding), average (L-grounding)	Average
Possible Operation With a Ground Fault	Not always	No	No	No	Not always	Almost always
Self-Extinguishing of Ground Faults	Not always	No	No	No	Not always	Almost always
Human Safety	Average	Good	Bad	Good	Average	Good
Equipment Thermal Stress	Low	High	High	High	Low	Lowest
Interference With Communications Lines	Average	High	High	High	Low	Lowest
Ground Fault Protection Sensitivity	Average	Good	Bad	Good	Average	Average

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