A Fresh Look at Limits to the Sensitivity of Line Protection

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A Fresh Look at Limits to the Sensitivity of Line Protection

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***Abstract*—This paper considers the sensitivity of essential line protection elements: ground distance and ground directional overcurrent elements applied as time-coordinated functions or in pilot-assisted protection schemes and line current differential schemes.**

Factors discussed include fault resistance, line unbalance and charging currents, impact of in-line reactors, system short-circuit capacity, load encroachment and swings, sequential tripping and weak feed terminals, steady-state and transient errors of instrument transformers, impact of current transformers (CTs) in dual-breaker line terminals, and single-pole-open conditions.

Protection element design improvements and application principles enhancing sensitivity are included.

I. Introduction

Just as blood vessels carry life-giving nutrients and oxygen to the body to sustain growth, transmission lines carry electric power from the generation source to load centers to sustain the economic life of a country. A fault on a transmission line decreases the power transfer ability of the power system and poses a possible threat to public safety. Therefore, to maintain the power transfer capacity of a power system and the safety of the public, faults need to be detected and cleared as rapidly as possible.

Power lines stretch long geographical distances and use air for insulation. Therefore, short circuits on power lines can happen under a variety of environmental conditions, including variations in soil resistivity impacting the tower grounding resistance, contact with trees and other objects, isolator flashover due to contamination, ionization of air due to fires in the vegetation along the right of way, arc resistance, and impact of wind, to name the most common scenarios.

Grounding of power line towers is less effective compared with substation grounding, and power lines are not surrounded with many solidly grounded objects. As a result, short circuits on power lines can be accompanied by relatively high fault resistance, particularly for single-line-to-ground faults.

High-resistance line faults draw limited currents and do not normally impact the power system from the dynamic stability and equipment damage points of view. However, power line faults are located in a public space, and as such, they can contribute to secondary effects if not detected with adequate sensitivity and speed.

Therefore, the sensitivity of line protection is an important power system protection consideration.

In this paper, we take a fresh look at challenges, solutions, and limits to the sensitivity of line protection [1].

First, we examine power system characteristics that contribute to the level of short-circuit currents, fault resistance, and the amount of standing unbalance under no-fault conditions.

Second, we look at protection signals with increased sensitivity to faults. High-resistance faults draw small fault currents that blend with load currents. Therefore, all practical sensitive protection methods tend to respond to fault components in the relaying signals. Using the negative-sequence and/or zero-sequence currents allows the relays to respond to a fault and filter out the standing symmetrical load current. Another solution is to use incremental components (fault values minus prefault values) to increase sensitivity. Yet another approach is to use differential measurements to increase sensitivity to the fault-generated currents and filter out the standing load currents. Some solutions can be combined to yield even better sensitivity, such as using the negative-sequence differential measurement for line protection.

Increasing the sensitivity of the operating signals on its own does not yield a complete protection element. A number of conditions can generate non-zero values of these ultra-sensitive operating signals. These conditions are instrument transformer errors—both transient errors and steady-state accuracy limits, finite accuracy and measurement range of applied relays, transients in the input signals and measuring algorithms, standing power system unbalance due to conductor positioning, open-pole conditions or single-phase shunt reactors, line-charging currents, imperfect data synchronization between line current differential relays, and so on.

The key to a sensitive, secure, and fast protection element is proper restraining techniques that ensure security against the many sources of error for ultra-sensitive operating signals, without erasing the original potential of the operating signals for sensitivity. Paradoxically, transient and high-current fault conditions are easier to deal with compared with standing or small errors that cannot be easily identified as related to external faults or similar events.

This paper reviews a number of techniques for deriving sensitive protection quantities and securing them against the many sources of error. In the context of sensitivity, we review challenges and element design techniques for overcurrent and directional elements, distance elements, and line current differential elements.

II. Line Characteristics Impacting the Sensitivity of Line Protection

Transmission lines make up the bulk of the power system, and therefore, their characteristics greatly determine the ability of protection devices to detect faults. We want to investigate what limits the sensitivity of detecting a fault in a transmission line.

As power engineers, we know that the construction (geometry) of a transmission line determines the self- and mutual impedances of the line [1] [2] [3]. Before we look at how line construction impacts line impedance, we will first examine what effect the line impedance has on the power system. Assume a simple transmission line model, as shown in Fig. 1.

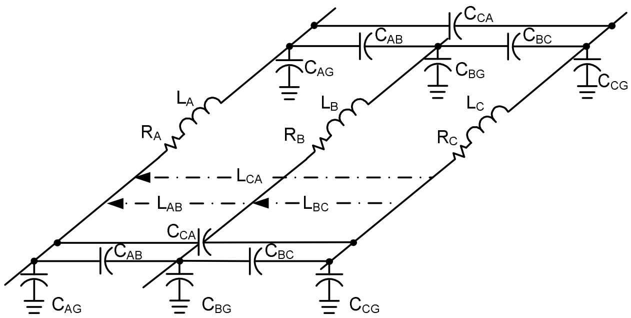

Fig. 1. Simple sketch of a transmission line model.

From Fig. 1, we can see that the transmission line model consists of series and shunt components. For easier understanding, we will analyze these two components separately.

For now, we will concentrate on the series components of a transmission line. If we only consider the series components, we can reduce the transmission line model to that shown in Fig. 2 (in this paper, we will ignore the effect of resistance; the reactance is usually an order of magnitude greater than the resistance).

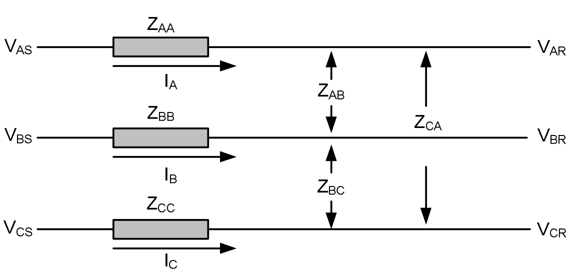

Fig. 2. Simple sketch of the current-dependent (series) components of a transmission line model.

We can write the following equation for the series components of a transmission line:

$$\begin{bmatrix} V_{AS} - V_{AR} \\ V_{BS} - V_{BR} \\ V_{CS} - V_{CR} \end{bmatrix} = \begin{bmatrix} Z_{AA} & Z_{AB} & Z_{CA} \\ Z_{AB} & Z_{BB} & Z_{BC} \\ Z_{CA} & Z_{BC} & Z_{CC} \end{bmatrix} \bullet \begin{bmatrix} I_A \\ I_B \\ I_C \end{bmatrix} \tag{1}$$

From (1), we can see that the voltage drop for a phase is not only dependent on its self-impedance (Z_{AA}, Z_{BB}, Z_{CC}) and line current but is also dependent on the mutual impedances (Z_{AB}, Z_{CA}, Z_{BC}) of the other phases and the currents in those phases. This means that if the self- and mutual impedances per phase are different, the voltage drop per phase will be different, even if the currents are balanced. The unequal voltage drop means that if we connect a balanced load to a balanced three-phase voltage supply via a transmission line, the individual phase currents drawn from the source will not be perfectly balanced due to the unbalance of the transmission line. This means that the transmission line introduces an unbalance into the power system.

Now, we will examine what determines the self- and mutual impedances of a transmission line. We know from literature [2] [3] that the self-impedance of a conductor basically only depends on the diameter of the conductor. This means that the self-impedances of each of the phases should be the same; however, this is not always true. Let us consider a typical transmission line with ground wires. If the ground wires are nonsegmented (continuous), they influence the self-impedance of the conductor (the presence of the ground wires reduces the self-impedance of the conductor). If the conductor is segmented, then the ground wire has no influence on the self-impedance of the conductor. The reason is that typically segmented ground wires are approximately 600 meters in length (two tower spans). The length of the segmentation is much shorter than the wavelength of a 50 or 60 Hz wave. The result is that the segmented wires carry no significant amount of current at the power system frequency, meaning the ground wires can be ignored for protection based on fundamental frequency components. If we find that the self-impedances of the transmission lines for a particular application are different, it is due to the phase conductors not being equidistant from the ground wire(s), an example of which is shown in Fig. 3.

In general, ground wires are typically segmented to reduce circulating currents in the earth and ground wires.

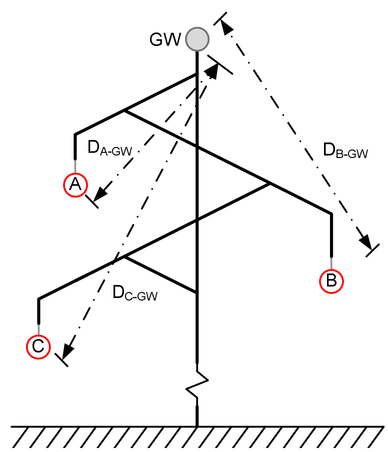

Fig. 3. Sketch showing phase conductors not equidistant from the ground wire.

Turning our attention now to mutual impedances, we know that they are influenced by the distance between the conductors (the farther the conductors are from one another, the lower the mutual inductance between them). Economics and ease of construction dictate why the conductors are not spaced equidistant from each other but are constructed in either a flat horizontal or vertical format, as is shown in Fig. 4.

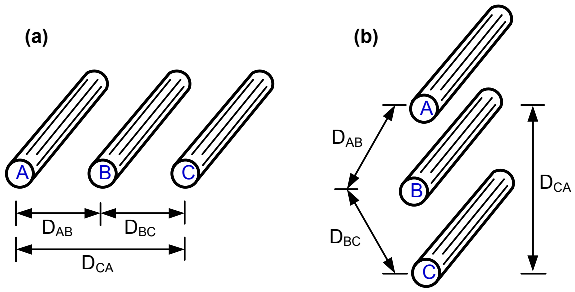

Fig. 4. Sketch showing some typical geometric arrangements of phase conductors.

The result is that at least one of the three mutual impedances is not equal to the other two. If we take the line shown in Fig. 3, short-circuit the R terminal end of the line, and connect it to a balanced three-phase supply (V_A, V_B, V_C), we can rewrite (1) in terms of the phase currents to get (2):

$$\begin{bmatrix} I_A \\ I_B \\ I_C \end{bmatrix} = \begin{bmatrix} Z_{AA} & Z_{AB} & Z_{CA} \\ Z_{AB} & Z_{BB} & Z_{BC} \\ Z_{CA} & Z_{BC} & Z_{CC} \end{bmatrix}^{-1} \bullet \begin{bmatrix} V_A \\ V_B \\ V_C \end{bmatrix} \tag{2}$$

The presence of ground wires does impact the mutual impedances of the line (they reduce the mutual impedance similarly as for the self-impedance case). In general, the ground wires are installed so that they protect all conductors equally from direct lightning strikes. This means that the ground wires are symmetrical about the center of the transmission tower (as is shown in Fig. 5) and will equally impact at least two of the three mutual impedances (if the conductors are placed symmetrically about the center line of the transmission line).

From what we have learned so far and assuming that the phase conductors are symmetrical about the center of the line, we can see the B-phase in (3) would draw a higher current than the A- and C-phases ($|Z_{AB}| = |Z_{BC}| > |Z_{CA}|$).

We would be well justified at this stage to ask the question: Why not construct the transmission line such that the conductors are equally spaced from one another?

Before we answer this question and see how engineers can take care of this unbalance issue, let us first examine the shunt components.

Considering only the shunt components of the transmission line model, we can derive an equivalent circuit model, as shown in Fig. 6.

Using the shunt component model of Fig. 6, we can derive (3) for the charging current of the transmission line:

$$\begin{bmatrix} I_{Ac} \\ I_{Bc} \\ I_{Cc} \end{bmatrix} = \left(j\omega \bullet \begin{bmatrix} C_{AA} & C_{AB} & C_{CA} \\ C_{AB} & C_{BB} & C_{BC} \\ C_{CA} & C_{BC} & C_{CC} \end{bmatrix} \right) \bullet \begin{bmatrix} V_{A\_ave} \\ V_{B\_ave} \\ V_{C\_ave} \end{bmatrix} \tag{3}$$

where:

$$C_{AA} := C_{AG} + C_{AB} + C_{CA}$$
$$C_{BB} := C_{BG} + C_{AB} + C_{BC}$$
$$C_{CC} := C_{CG} + C_{CA} + C_{BC}$$

The subscript *_ave* denotes the average voltage along the line length

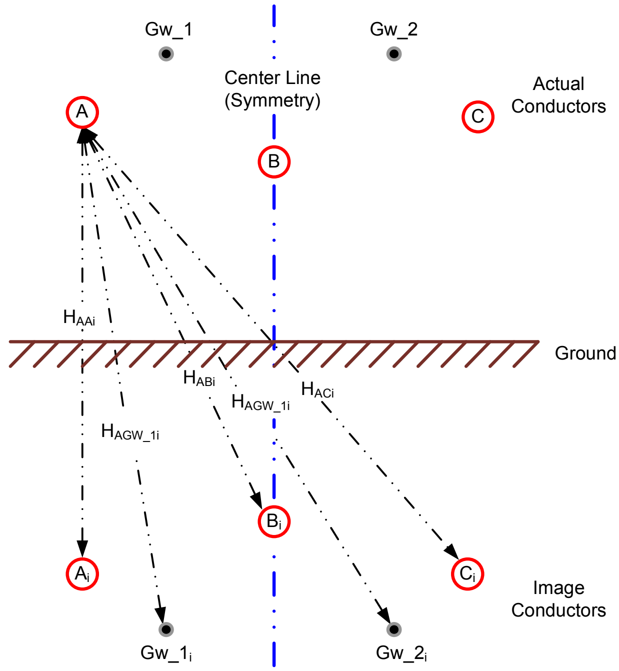

Fig. 5. Sketch showing actual and image conductors of a transmission line.

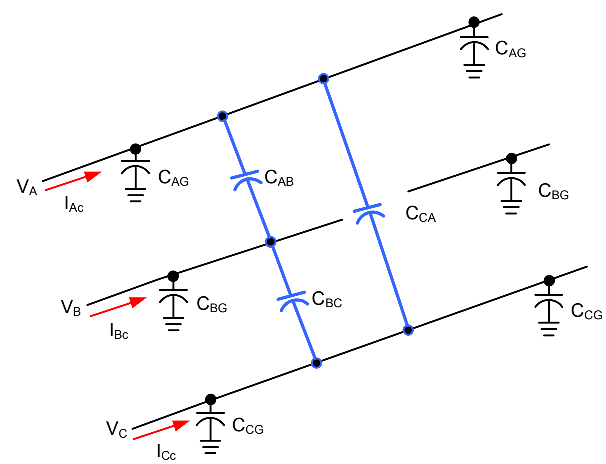

Fig. 6. Simple sketch of the voltage-dependent (shunt) components of a transmission line model.

Again, we can see that the charging current is dependent not only on the self-capacitance of the line but also on the mutual capacitance between the phases.

Note that (3) is different than (12) introduced later in this paper. This is because (3) is used to calculate the root-mean-square (rms) value of the charging current using the average voltage across the line, whereas (12) is used to calculate the instantaneous value of the charging current.

The self-capacitance of a conductor is directly proportional to the diameter of the conductor and inversely proportional to the distance between the conductor and its image. An image conductor is an imaginary (virtual) conductor that is the same distance below ground as the actual conductor is above ground. Fig. 5 is a sketch of a transmission line and its image.

Ground wires are installed to protect (shield) the phase conductors from direct lightning strikes. As is the case for series components, ground wires may also influence the self-capacitance of a transmission line. When conducting steady-state studies, the same rule that is applied for the series components also applies to shunt components. If the ground wires are segmented, we ignore them; if not, we need to account for them.

When conducting transient studies (such as lightning studies), regardless of whether the ground wires are segmented or not, they have to be taken into account. The reason is that the wavelengths at these frequencies are short enough that they result in currents in the ground wires.

If the conductors of all three phases are the same height above ground, then they generally have the same self-capacitance (if the ground wires are ignored). If the conductors are not the same height above ground, the self-impedances will be different. The effect of the ground wires is that they increase the self-capacitance of the conductors.

The mutual capacitances are directly proportional to the distance between the conductors (D_{AB}) and inversely proportional to the distance between the one conductor and the image of the other conductor (H_{ABi}). No matter how we position the phase conductors, we will never get all the mutual capacitances to be the same.

So from what we have learned, no matter how we position the conductors, each phase will not draw the same charging current. The above statement answers the earlier question we asked: Why not simply space the conductors equidistant from one another? We see now that if we did this, we would certainly get the same self- and mutual impedances per phase, but this would not be true for the capacitances.

The phase currents drawn when a load is connected to a source via a transmission line not only depend on the impedance of the load but also depend on the impedance and capacitance of the transmission line. In general, the charging current of a line is directly proportional to the length and voltage of the line. Because the length and voltage are generally fixed, the charging current of a line is generally constant. However, we know that the load current varies, meaning that the voltage drop across the line will vary. From the above, we can write an equation for the current drawn from a source to a load via a transmission line:

$$\begin{bmatrix} I_A \\ I_B \\ I_C \end{bmatrix} = \begin{bmatrix} I_{A\_c} + k \bullet I_{A\_l} \\ I_{B\_c} + k \bullet I_{B\_l} \\ I_{C\_c} + k \bullet I_{C\_l} \end{bmatrix} \tag{4}$$

What (4) tells us is that current drawn from a source (I_ϕ) consists of a charging current (I_{ϕ_c}, which is fixed) for a transmission line and a fraction (k = 0 through 1) of the maximum load current (I_{ϕ_l}). At this stage, we can introduce a current unbalance, which we define as per (5):

$$I\phi_{UNB} = \left[\frac{I\phi}{I_{Average}} - 1 \right] \tag{5}$$

where:

$$I_{Average} := \frac{(I_A + I_B + I_C)}{3}$$

Equation (4) also tells us that the current unbalance is not fixed but is dependent on load.

From what we have learned so far, we cannot balance shunt and series impedances of a transmission line by conductor position alone. So engineers divide the length of the transmission line into three equal parts (or a multiple of three equal parts) and let each phase conductor occupy a position for a third of the line length. This is known as transposition. This means that if we examined the entire line, the self- and mutual impedances would all be the same. The same would be true for shunt components.

Does this mean that because we have perfectly transposed all our transmission lines and have no unbalance currents, we can detect all faults in our system by detecting an unbalance between the phase currents? The answer is unfortunately no. Remember that the lines are typically transposed every one-third of the line length. If we should get a fault within our line, the line sections between the stations and the fault are no longer fully transposed, and we would again see an unbalance, not only due to the fault but because of the nonsymmetry of the line sections.

This tells us that due to built-in nonsymmetry, transmission lines are their own worst enemies in detecting faults that require greater sensitivity.

III. Impact of Instrument Transformers on the Sensitivity of Line Protection

Ratings and steady-state and transient errors of instrument transformers have a considerable impact on protection sensitivity. Protective relays apply a number of countermeasures to cope with instrument transformer errors while balancing security against speed and sensitivity. The relays cannot, however, re-create information that is lost through the finite accuracy of instrument transformers. In this section, we discuss some of the major limiting factors to sensitivity originating in the accuracy of instrument transformers.

A. Measuring Tolerances Under Near-Nominal Conditions

High-resistance faults do not cause significant changes in currents and voltages. Therefore, the accuracy of instrument transformers under near-nominal conditions is one of the main concerns for the sensitivity of protection. These errors are primarily standing errors and cannot be dealt with using a time delay. They require permanent security measures and therefore impact the sensitivity of protection.

A 1 percent ratio error in one phase under nominal conditions translates into a spurious 0.01 pu signal in the 3I2 (or 3V2) and 3I0 (or 3V0) quantities.

A 1-degree angle error in one phase under nominal conditions translates into a spurious 0.0175 pu signal in the 3I2 (or 3V2) and 3I0 (or 3V0) quantities.

The ratio and angle errors add geometrically. For example, a combined 1 percent ratio error and a 1-degree angle error yield a total error of $(0.01^2 + 0.0175^2)^{0.5} = 0.02$ pu.

Both the ANSI and IEC current transformer (CT) accuracy classes for relay applications limit the magnitude errors at the rated current to either 1 percent (X and 5P) or 3 percent (C/T and 10P) and the maximum composite errors (combined magnitude and angle) to 5 or 10 percent.

Voltage transformers (VTs) have a typical accuracy of 1 or 2 percent of ratio error and 0.7 or 1.3 degrees of angle error.

Sequence voltage and currents are composite signals derived from all three-phase voltage and currents, respectively. Errors in each of the phases can compound or mutually cancel in these composite signals. Common factors influencing accuracy, such as temperature, will tend to yield mutually, canceling errors for the sequence components. In general, however, it is beyond practical engineering to anticipate specific values of spurious sequence currents or voltages as resulting from the accuracy of instrument transformers under near-nominal conditions.

Proper application of instrument transformers, such as grounding and cable shielding, needs to be followed in order to minimize the amount of error in ultra-sensitive line protection applications.

Standing errors in sequence currents and sequence voltages are addressed differently in protective relays.

Sequence currents are typically used as operating signals (ground directional overcurrent and differential). Positive-sequence restraint—using a small portion of the positive-sequence current to dynamically raise and lower the operating threshold—is a good solution that maximizes both sensitivity and security.

Sequence voltages are typically used as polarizing signals (in ground directional overcurrent functions, primarily). Here, the concept of the offset impedance is used to counter the voltage measurement errors. Consider a negative-sequence directional element. For reverse faults, the negative-sequence voltage at the relay point is at least the line impedance times the measured current; for forward faults, the voltage is the local system impedance times the measured current. This separation in voltage values for forward and reverse faults creates a good margin for voltage errors, as explained in more detail in Section IV.

Negative- or zero-sequence current can be used for polarization of the reactance characteristic in a quadrilateral distance element. Measurement errors in the angular position of these polarizing quantities can result in very large distance measurement errors if the resistive reach is set too far. Section V elaborates on this issue.

One novel way to apply sensitive protection is to monitor the instrument transformers for out-of-tolerance conditions using synchronized phasors via phasor measurement unit (PMU) functions of microprocessor-based relays [4] [5]. In a typical substation, both currents and voltages are measured with a fair amount of redundancy, allowing for detection of errors in instrument transformers.

For example, a number of line-side VTs can be effectively connected to the same bus, and their measurements can be directly compared. Currents around each electrical node can be compared for consistency using Kirchhoff's current law.

PMUs measure with an accuracy of 1 percent of total vector error (TVE) as per IEEE C37.118, which corresponds to a total error of 1 percent (1 percent of ratio error or 0.6 degrees of angle error). Applying averaging over multiple PMUs and instrument transformers, a PMU-based monitoring system can estimate true values of currents and voltages with accuracy even higher than 1 percent TVE, allowing very sensitive detection of instrumentation errors. The outlying measurements can be flagged and trusted less (or even omitted) when applying very sensitive protection functions.

When using this approach, problems with instrument transformers and cabling can be rectified before they develop into more significant measurement errors or lead to catastrophic failures of instrument transformers. Protective relays can be signaled to reduce their originally high sensitivity in order to maintain security if their input sources perform outside of their best tolerance.

B. Saturation of CTs

CT saturation is a drastic case of a measurement error creating spurious protection quantities of significant magnitudes.

Sequence currents—being a basis for most of the sensitive line protection elements—are particularly vulnerable. Consider a three-phase balanced fault, such as when closing on safety grounds inadvertently left after equipment maintenance. True (primary) negative- and zero-sequence signals are zeros (or very close to zero), but saturation of one or more CTs would generate spurious 3I2 and 3I0 in the secondary currents. A directional comparison blocking scheme would experience security problems because one of the line terminals may see a forward fault when using 3I2 or 3I0 measurements, while the other may not establish a block. A differential scheme would not have any actual through 3I2 or 3I0 to restrain from or block. Similar concerns apply to the 3I0 measurements during external phase-to-phase faults. These problems only amplify in the case of dual-breaker line terminations, as explained in the next subsection.

Both the so-called "ac saturation" due to high ac current components and "dc saturation" due to large and long-lasting dc components should be considered. The latter is important near generating stations and equipment with large X/R ratios. DC saturation can potentially be more damaging to the security of sensitive protection functions because it could happen under relatively low currents and, consequently, relatively low restraining measures applied by the relay.

Rating the CTs adequately solves the problem. However, the no-saturation condition as per IEEE C37.110 may be difficult to meet under very high X/R ratios. One solution to this problem is to make sure the CTs do not saturate for the duration of external faults and/or to apply enough time delay to sensitive protection functions to effectively time-coordinate between clearing an external fault and operating for a high-resistance internal fault.

Positive-sequence restraint can provide some security to the sequence currents under CT saturation. However, deep saturation requires considerable restraining, which eventually erases the natural sensitivity of protection elements based on 3I2 or 3I0.

Another way to secure the sensitive elements responding to 3I2 and/or 3I0 is to inhibit them if the phase currents are relatively high. High current levels signify the possibility of an external fault and elevated errors in CTs. For internal faults, high current levels allow less sensitive protection functions (such as distance) to pick up, so there is no erosion in the overall sensitivity of the scheme.

Line current differential elements are capable of providing external fault detection and controlling the balance between security and sensitivity in a dynamic manner—engaging high security only for external faults, as explained in detail in Section VI.

C. Dual-Breaker Line Terminations and CT Errors

Dual-breaker line terminations (breaker-and-a-half, ring-bus, double-bus double-breaker) create extra challenges to sensitivity and security if breaker CTs are used for line protection (see Fig. 7).

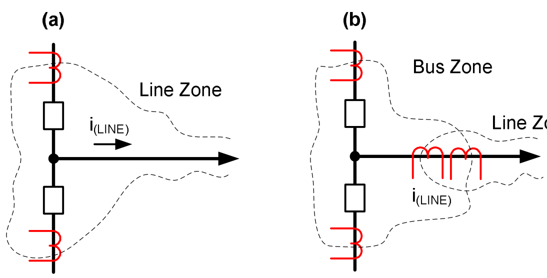

Fig. 7. Dual-breaker line termination—breaker CTs used to derive the line current (a) and a line CT used to measure the line current (b).

First, the breaker CTs can be rated much higher compared with the line rating. A 1000 A line can be terminated at a 5000 A dual-breaker bus connection, for example. The higher breaker rating is dictated by the ratings of other lines or transformers connected in the station. A 1 percent tolerance error of a fully loaded 5000 A CT would yield 50 A of spurious 3I2, which is as high as 5 percent of the 1000 A line rating. Sensitivity will suffer in dual-breaker applications if the diameter ratings are considerably higher than the line ratings. If sensitivity is of primary concern, line CTs should be installed and used for line protection and a separate bus protection zone should cover the area between the line CT and the two breakers.

Second, high through-fault currents could flow through the two breakers, causing CT saturation and resulting in errors in the derived line current while the actual line current may be low and limited by the remote system and line impedance. For example, consider a 10 percent error due to CT saturation during a 20 kA through fault on the 5000 A breaker connection. This 2 kA error is 200 percent of the line rating. If the actual fault contribution through the line is at this level or lower, the line relay could see a complete current reversal and sense the fault as forward. Sequence currents (3I2 and 3I0) during three-phase balanced faults and phase-to-phase faults are particularly vulnerable.

Again, using line CTs instead of the breaker CTs alleviates the problem if the breaker CTs cannot be rated to avoid saturation.

D. Transients in Instrument Transformers

Sensitive protection functions do not have to respond very quickly to high-resistance faults. Therefore, quite often, an intentional time delay is applied to ride through transient errors due to instrument transformers, such as capacitance voltage transformer (CVT) errors. The applied time delay also allows ride through for other transients, such as uneven breaker pole opening, external faults cleared with no intentional time delay, and load switching.

IV. Sensitivity and Application of Directional Elements

High-resistance faults are unbalanced faults, primarily single-line-to-ground faults. These faults can be detected via negative- and zero-sequence quantities.

Positive-sequence quantities are required to detect symmetrical faults (three-phase faults), but these faults are extremely unlikely to be high resistance and therefore do not require sensitive protection. Positive-sequence quantities are heavily influenced by load and have limited sensitivity. In cases of passive or weak line terminals, weak-infeed logic can be used to detect symmetrical faults. This paper does not discuss the sensitivity of protection elements that are exclusively based on positive-sequence quantities.

Ground directional overcurrent elements are very effective in detecting high-resistance faults on transmission lines. These elements respond to the negative- or zero-sequence currents and can be polarized in a number of ways. They trip with time coordination as single-ended functions or with minimum time delays via directional comparison schemes.

A. Choice of the Operating Signal

Negative-sequence current allows the detection of all unbalanced faults. From this perspective, it may be more beneficial to use negative-sequence current as compared with zero-sequence current, because the latter is activated only during ground faults.

Even though most high-resistance faults involve ground, fault resistances are typically much smaller between the phases than between the phases and ground. This favors negative-sequence current as the operating quantity when multiphase ground faults are considered.

True negative-sequence current flows for all fault types except perfectly balanced three-phase faults. This means not only better dependability but also better security under CT saturation. The false 3I2 component would cause a problem only if it overrides the natural (true) 3I2 signal. So with the true 3I2 flowing during all but symmetrical faults, there is more room to accommodate CT errors and saturation. The true zero-sequence current is zero under both three-phase symmetrical and phase-to-phase faults, making it more vulnerable to CT saturation because phase-to-phase faults are more common compared with symmetrical three-phase faults.

Mutual zero-sequence coupling between the protected line and other lines is yet another factor to consider. Mutual coupling primarily affects polarization based on 3V0. In the context of the operating current, mutual coupling may play a role if in-zone grounding sources are present, such as reactors.

The short-circuit levels for the negative- and zero-sequence currents are a major selection criterion, however. In cases where the system is weak but includes many grounding sources, levels of the zero-sequence currents for internal faults will be much higher than the negative-sequence currents, and this favors zero-sequence as the operating current.

Detailed short-circuit studies should be conducted to make the determination regarding the choice between zero- and negative-sequence currents. In this context, we need to assume all reasonable scenarios related to the grounding sources in the vicinity of the protected line. Negative- and zero-sequence current levels may have different variabilities with respect to the network operating conditions.

Finally, we need to remember that proper coordination must be followed between the line terminals or even throughout the system. A directional comparison blocking scheme cannot use negative-sequence to assert the forward direction and zero-sequence to assert the blocking signal. Similarly, a negative-sequence time-overcurrent element may miscoordinate with a zero-sequence element, even if their curves are properly selected. The choice of the operating quantity must be consistent given the application context.

Positive-sequence current restraint is typically used to manage CT inaccuracies (Section III) and system unbalances (Section II). The amount of positive-sequence restraint must be harmonized in order to ensure coordination if the ground overcurrent element is set very sensitive.

B. Choice of the Polarizing Signal

Directional discrimination is provided through polarization using negative-sequence voltage, zero-sequence voltage, ground current, or a combination thereof.

Sequence voltages provide excellent polarization for directional elements applied to transmission lines (series-compensated and mutually coupled lines require special considerations). Consider negative-sequence polarization. As shown in Fig. 8, the negative-sequence voltage can be legitimately located in one of the two shaded areas, given the negative-sequence current. This is because the three involved impedances (local and remote systems and line) are typically very homogeneous. These impedances govern the voltage/current relationship for the negative-sequence equivalent network. This means the negative-sequence voltage provides a large room for error without impacting dependability or sensitivity.

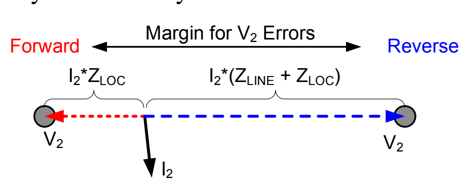

Fig. 8. Negative-sequence voltage is driven by the system and line impedances with considerable margin for measurement errors.

The zero-sequence voltage displays similar resilience to measurement errors but is somewhat less robust because the zero-sequence impedances are generally less homogeneous.

Also, the zero-sequence voltage can be severely affected by mutual coupling. Zero-sequence currents in the coupled line or lines induce a voltage drop in the protected line, with consequences potentially as severe as voltage inversion.

Using local station ground current (a current from an available grounding source in the substation, such as a wye-grounded winding of a power transformer) for detecting directionality of the zero-sequence line current is another option. The line zero-sequence and the polarizing ground currents are typically almost perfectly in phase or out of phase, depending on the fault direction. This method should not be used when the grounding source is disconnected from the system. Using several ground source currents via paralleled CTs may be an option.

Typically, the higher the magnitude of the polarizing quantity, the better its directional integrity. One solution to polarization of directional elements is to allow for automatic selection of a polarizing signal based on actual fault and system conditions, while following a user-defined preferential sequence [5] [6].

C. Impact of Line-Charging Currents

Line-charging current does not affect ground directional overcurrent elements as long as the systems are not very weak. Note that the capacitive impedance of the line appears in parallel with the line local and remote system impedances. The remote system impedances are all inductive and smaller, while the local system impedance is capacitive and much larger. This means the equivalent impedance of the parallel connection is inductive and slightly larger than the system or line impedance alone. This increase in the impedance reduces the amount of the available sequence current, but only slightly.

Note that a high fault resistance causes the zero- and negative-sequence currents to be small. This does not pose a problem when combined with the line-charging current. The zero- and negative-sequence charging currents are also very small when a high-resistance fault is present (we should not confuse the positive-sequence charging current with the zero- and negative-sequence charging currents). The positive-sequence charging current can be much higher than the available zero- and negative-sequence currents during high-resistance faults, but it does not obstruct the operation of the ground directional elements.

The line-charging current could be a factor in very weak systems—systems with the equivalent impedance comparable with the shunt impedance of the line. In this case, the apparent impedance seen from the fault toward the relays and sources can divert from being inductive, challenging the principle of sequence directional elements. From this perspective, the zero-sequence elements are typically less affected because even passive terminals typically have a grounding source in the form of a step-down transformer.

D. Applications With Time-Coordinated Schemes

Negative- or zero-sequence ground time-overcurrent protection elements with directional torque control can provide sensitive line protection.

A natural advantage of the sequence overcurrent elements is that the operating current decreases as we move away from the unbalance (fault or open pole) and toward the sources (generators and grounding points). With reference to Fig. 9, each grounding source or fault-contributing branch acts as a shunt for the sequence currents. This decrease in the current level as we move away from the fault brings a natural margin for the time-coordinated ground directional overcurrent schemes and makes directional torque control a less critical aspect of the application. Zero-sequence currents benefit more from this observation because the grounding points shunt extra zero-sequence current as compared with negative-sequence current.

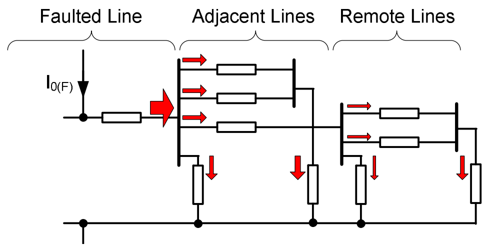

Fig. 9. Zero-sequence current decreases away from the fault, aiding time coordination of the ground time-overcurrent elements.

Still, the scheme needs to be properly coordinated. This includes the following in addition to the plain time-current operating characteristics:

- The same operating current (zero- or negative-sequence) should be used throughout the entire system.
- Similar directional elements should be used throughout the entire system.
- Similar element design should be used throughout the entire system. For example, positive-sequence restraint, if applied, can make some of the locations less likely to pick up because of the higher load carried at those locations.

Because of the above requirements of system-wide coordination, applications of time-coordinated ground overcurrent protection in high-voltage systems are mostly driven by the existing utility practice.

E. Applications With Directional Comparison Schemes

Directional comparison schemes working with sensitive ground directional overcurrent elements allow fast operation for high-resistance faults. Several application aspects are worth mentioning.

First, directional elements, if set very sensitive, typically incorporate some intentional time delay to increase security during transients. Often, the applied time delay is in the order of a few cycles and allows riding through external faults cleared by instantaneous protection elements.

Second, because of their high sensitivity, ground directional elements call for current reversal logic in the directional schemes. This is to avoid coincidence of the forward indications at both ends of the line when clearing external faults. The current reversal logic is important even for nonparallel lines because the very long reach of ground directional overcurrent elements allows them to see faults through distant parallel paths, including lower-voltage networks.

Third, blocking schemes call for rigorous coordination of the operating principles for tripping (forward) and blocking (reverse) elements, if set very sensitive. Operating signals, methods of polarization, and the amount of positive-sequence restraint must be carefully matched. In particular, the same operating signal must be used, the blocking pickup threshold must be lower than the tripping pickup threshold, and preferably the positive-sequence restraint must be removed from the blocking elements. When applying single-pole tripping, the blocking action from the open-pole detector must be carefully set to avoid unblocking at the terminal that recloses first, while the other line end has its sensitive functions still blocked and is incapable of asserting a block.

Fourth, permissive schemes are more secure when attempting to provide very high sensitivity. Blocking schemes are naturally biased toward greater sensitivity by requiring just one line terminal to see enough sequence current in order to trip. By the same logic, however, they are less secure if the ultra-sensitive ground directional overcurrent element asserts spuriously.

F. Sequential Tripping

Fault resistance allows the voltage at the fault point to remain relatively high. Under this condition, if the two equivalent sources are of considerably different short-circuit capacity, the stronger system will further prevent the weaker terminal from feeding much fault current by lifting the voltage at the fault point. As a result, only the stronger terminal may see the fault as it draws more fault current. This phenomenon applies not only to distance elements but to ground directional overcurrent elements as well. If the element is allowed to trip without permission from the other line end (Zone 1, a blocking scheme), the strong terminal will trip first. Once the breaker opens and the infeed condition is removed, the weaker terminal may be able to see the fault and trip as well. In some applications, sequential tripping is allowed and can greatly improve the overall sensitivity of protection at the expense of delayed tripping. We need to engineer the scheme correctly to ensure at least one terminal is able to trip first and remove the infeed. Autoreclosing needs to factor in the possibility of sequential tripping.

V. Sensitivity of Distance Elements

In general, high-resistance faults are associated with single-line-to-ground faults. For these faults, the associated fault resistance (R_F) can be considerable and, as such, be the dominating factor in detecting these faults. Phase-to-phase faults, on the other hand, do not involve high resistance, and the fault resistance is not the dominating factor in detecting these faults. For the purpose of this paper, we primarily focus on single-phase-to-ground faults. We begin by examining a single-line-to-ground fault and the factors that influence its detection. Fig. 10 is a sketch of the simple power system we will use for this.

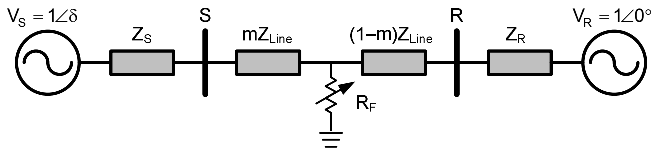

Fig. 10. Simple power system model used to analyze the performance of distance elements.

We can equivalize the simple power model from Fig. 10 to that shown in Fig. 11 for a single-line-to-ground fault in the power system.

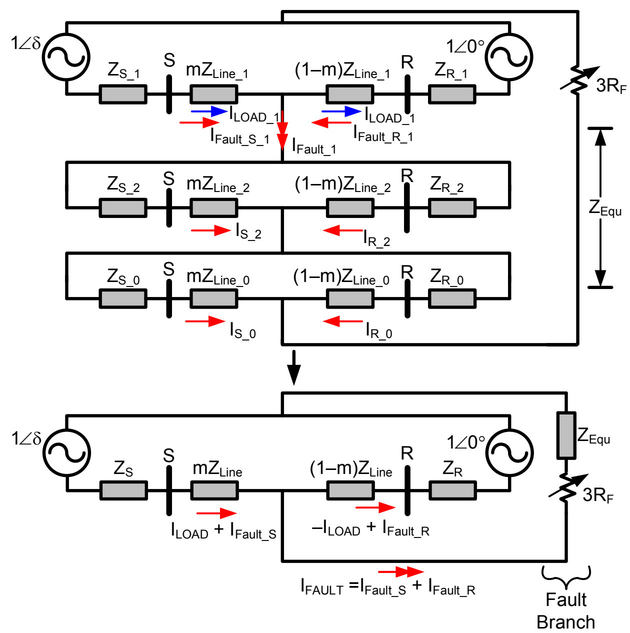

Fig. 11. Equivalent sequence diagram for a single-line-to-ground fault.

From Fig. 11, we can see that the following two factors primarily influence the current flow at each terminal:

- The angular difference between the sources, which determines the level of the load current.
- The impedance of the fault branch. If the fault resistance (R_F) is low, then the dominating factor for the fault current is predominantly the system and line equivalent impedance (Z_{Eq}), and if the fault resistance is high (much larger than Z_{Eq}), the fault resistance becomes the dominating factor.

Basically, two types of distance elements exist, mho distance elements and quadrilateral distance elements.

We examine the mho distance element first. The mho distance element describes a smooth curvature on the impedance plane. This smooth curvature is the result of an angular comparison between two quantities: an operating quantity (6) and a polarizing quantity (7). If the angle between these two quantities < |90°|, the element operates.

$$\delta V_\varphi = \left[Z_{set} \bullet \left(I_\varphi + k_0 \bullet I_R \right) - V_\varphi \right] \tag{6}$$

$$V_{POL} \tag{7}$$

What effect does fault resistance have on the mho distance element? When we have a fault with zero fault resistance ($R_F = 0$), we know from Fig. 11 that the system equivalent impedance will determine the magnitude and angle of the fault current. The fault current will be the dominant current through the faulted terminal. If the system is homogeneous, what we will find is that the angle between the operating quantity (6) and the faulted phase voltage (this could be the polarizing quantity) is approximately zero. This is because the voltage drop term ($Z_{set} \bullet (I_\varphi + k_0 \bullet I_R)$) is the dominant term in (6). As the fault resistance increases, the fault resistance begins to determine the magnitude and angle of the fault current—the fault current no longer is the dominant current term through the terminal but is surpassed by the load current. The voltage drop term in (6) becomes less dominant, resulting in the angle between the operating quantity and the faulted phase voltage increasing. Once the angle between these two quantities becomes greater than 90 degrees, the mho element no longer sees the fault within its operating zone. One way designers overcame this obstacle was by using a polarizing signal other than the faulted phase voltage (for example, the unfaulted phase voltage or the positive-sequence memory voltage). This also gave the element other advantages, such as stability for faults close into the terminal, in addition to allowing the element to see faults with greater fault resistance (Fig. 12).

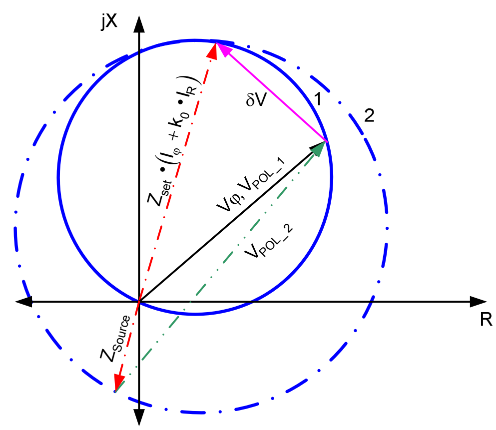

Fig. 12. Mho distance element characteristic with self-polarized (1) and cross- or memory-polarized voltage (2).

The effect of using a voltage other than the faulted phase voltage as the polarizing signal results in the mho element expanding towards the source. This expansion is inversely proportional to the source strength: the weaker the source, the greater the expansion, and vice versa. Note that despite the expansion, the resistive fault coverage near the end of the reach is not improved. In essence, the mho element sensitivity for higher-resistance faults is dependent on the strength of the source behind it and the location of the fault.

Now let us consider the quadrilateral ground distance element. A quadrilateral distance function is made up of four elements:

- A reactance element determines the impedance reach of the function.
- Two resistive blinders, one right-hand side blinder and one left-hand side blinder, determine the resistive coverage of the function.
- A directional element determines the directionality of the fault.

Fig. 13 shows a typical forward directional quadrilateral element made up of the above elements.

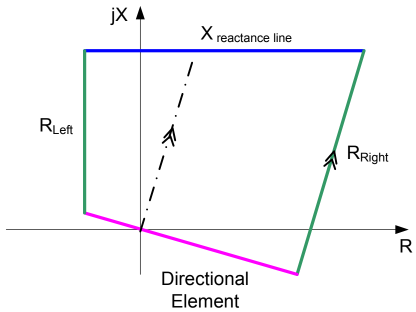

Fig. 13. Forward-looking quadrilateral distance element characteristic.

The directional element and what affects its sensitivity are discussed in Section VI.

The reactance element is very similar to the mho element; both elements use the same operating quantity. The difference is that the mho element is polarized by voltage, whereas the quadrilateral element is polarized with current. Equations (8) and (9) describe the operating and polarizing quantities for the reactance element:

$$\delta V_{\varphi} = \left[Z_{set} \bullet \left(I_{\varphi} + k_0 \bullet I_R \right) - V_{\varphi} \right] \tag{8}$$

$$I_{Pol} = j \bullet I2 \tag{9}$$

Reference [7] discusses why the negative-sequence current is best for polarizing the reactance element—basically, it allows the element to adapt for load and prevents the element from overreaching for an external fault with fault resistance.

The resistive elements are responsible for the resistive coverage of the quadrilateral element. These elements should provide the greatest resistive coverage possible without compromising the element. If we examine Fig. 11 from the S terminal (outgoing load), we see that the resistance of the load is one of the factors that limits the ability of the element to detect higher-resistance ground faults, similarly for the R terminal (incoming load). To obtain maximum fault coverage for load in either direction, [7] proposes the use of adaptive resistive blinders/elements (similar to the reactance element). These elements are similar to the reactance element in that they are composed of an operating quantity and a polarizing quantity. The operating quantity is similar to that used for the reactance element, except that R_{set} replaces Z_{set} in (8). To obtain the best possible coverage for both incoming and outgoing load, [7] proposes running two adaptive resistance elements in parallel—one that is polarized with negative-sequence current (this provides maximum resistive coverage for outgoing load) and one polarized with a composite signal made up of the sum of the positive- and negative-sequence currents (maximum coverage for incoming load).

Other factors that must be taken into account when setting the resistive blinders are:

- Is the scheme employed on a system where single-pole tripping is enabled? If so, the reach must be coordinated with the load, because if there is a pole open on a parallel feeder or on a feeder further down, these elements may inadvertently overreach and operate during the pole-open condition.
- Instrumentation errors (CT and VT errors) can cause the reactance element to overreach for an out-of-section fault, especially when the resistive reach is set much greater than the reactive reach.

VI. Sensitivity of Line Current Differential Elements

A. Overall Characteristics of Line Current Differential Elements

Line current differential elements can provide very sensitive protection, particularly through the application of sequence differential elements (negative-sequence or zero-sequence), as explained later in this section.

The following are natural advantages of the differential principle as related to the sensitivity of protection:

- The operating (differential) signal includes fault contributions from all terminals, and therefore, the principle does not suffer if some of the line terminals are weak.
- The differential element measures all currents that bound the line zone and can apply better security measures for external faults as compared with any single-ended protection method.
- The load and system unbalance currents are naturally eliminated from the operating signal in a way that does not impact security.
- Voltage signals are not used, and voltage measurement errors do not limit the sensitivity of protection.

On the other hand, line current differential protection faces the following unique challenges due to the physical dimension of the line as a protection zone:

- Line-charging currents and currents of in-zone reactors appear as a differential signal.
- Line reactors can appear in zone or out of zone, depending on the way their CTs are used in the differential zone. With in-zone reactors, mutual coupling with parallel lines can play a role because the reactors constitute a ground path inside the zone of protection.
- Errors in the synchronization of data between relays at different line terminals can create a false differential signal, both in a steady state as well as during faults. These errors can impact both the security and sensitivity of line current differential protection.

Finally, line current differential elements are prone to errors in current measurements, specifically:

- CT tolerances can yield a standing differential signal of a few percent of nominal. Depending on the number of line terminals (two, three, or more) and bus configuration (single- or dual-breaker line terminations), two or more CTs can be involved when creating a phase differential signal. For example, six CTs are used in a three-terminal line with a breaker-and-a-half at each terminal. For sequence differential elements, the number of involved CTs is three times higher. For example, 18 CTs are used to calculate the negative-sequence differential in a three-terminal line with dual-breaker connections at each terminal. The tolerances of the many CTs that bound the differential zone can compound or mutually cancel.

- CT saturation during external faults can create significant spurious differential currents, calling for a means of stabilizing the function. This is particularly important for sequence differential elements because these elements may not have any legitimate restraint under certain fault types, as explained in Section III.
- CT trouble conditions (open CT) can jeopardize the security of sensitive differential protection and therefore call for adequately fast and sensitive open CT detection elements.

The above advantages, challenges, and limitations apply differently to phase and sequence differential elements.

B. Phase Differential Elements (87LP)

The sensitivity of phase differential elements is affected by charging currents, load currents contributing to the restraining mechanism, and data synchronization errors.

The line-charging current can be in the order of 1 to 2 A primary per mile of the line length, and for long lines, it can add up to hundreds of amperes. This is a positive-sequence current, and as such, it appears as a standing phase differential signal. The phase-charging current cannot be dealt with by increasing the restraint—when the line carries no load, the charging current appears as a single-feed current and therefore can be inhibited only by raising the pickup threshold, thus eroding sensitivity of the 87LP element. Moreover, under line pickup conditions, the inrush charging current appears considerably higher compared with the steady-state value, calling for an even higher increase in the pickup threshold, at least temporarily.

The load current contributes to the restraining mechanism of the phase differential functions. This is true regardless of the type of differential comparator (percentage differential or Alpha Plane). Simply, the line terminal currents appear relatively out of phase, given the small differential current created by high-resistance faults. In order to respond to such faults, the restraining mechanisms would have to be designed or set to restrain less, but this could jeopardize security during external faults.

Synchronization errors (imprecise alignment between the local and remote currents) also create standing phase differential current. This kind of error can be dealt with by means of a restraining mechanism (percentage slope or Alpha Plane blocking angle), resulting in degraded sensitivity.

C. Sequence Differential Elements (87LQ and 87LG)

Negative-sequence (87LQ) and zero-sequence (87LG) line current differential elements are naturally more sensitive compared with the phase elements.

First, the negative- and zero-sequence charging currents during high-resistance faults are relatively small. A high-resistance fault creates a small voltage unbalance and, correspondingly, a small charging current unbalance.

Second, the sequence differential elements use a corresponding sequence restraining mechanism—for example, the negative-sequence differential can be restrained with a negative-sequence current (percentage restraint or Alpha Plane). As a result, these functions are not overrestrained by the standing load current. On the other hand, they require extra security under external faults, as explained later in this section.

Third, the equivalent system sequence networks (negative-sequence networks in particular) are typically very homogeneous. This means that under internal fault conditions, the negative-sequence components supplied from all line terminals are in phase with one another or differ by only a few electrical degrees. During external faults, these currents are virtually out of phase with one another. This large angular separation yields the best possible margin between internal and external faults and allows designing or setting the restraining mechanism, such as the blocking angle of the Alpha Plane, in a very conservative way without impacting sensitivity.

Because the negative-sequence currents contributing to an internal fault are almost all in phase, we have a bigger security margin when it comes to the impact of synchronization errors. For example, if we set the Alpha Plane to operate for angle differences of up to 75 degrees, we retain dependability under synchronization errors of up to 75 degrees (local and remote currents are truly in phase but appear 75 degrees apart because of synchronization errors). At the same time, we retain security for errors of up to 105 degrees (the two currents are truly out of phase but appear 75 degrees apart because of the 105 degrees of synchronization error).

D. External Fault Detection

External fault detection (EFD) logic allows relaxing CT requirements and reducing the engineering effort to verify a given application with a given set of CTs. From the sensitivity point of view, EFD logic allows differential elements to cope with possible CT errors under external faults without reliance on excessive restraining means and associated penalties in sensitivity. Instead of having the restraining means (percentage slope or Alpha Plane blocking) engaged permanently, the line current differential relays with EFD algorithms increase security dynamically only upon detecting an external fault in anticipation of possible CT saturation.

Fig. 14 presents a simplified diagram of the EFD logic. This method has been developed for bus and transformer differential relays and also used in line current differential schemes [8]. An increase in the instantaneous restraining signal (above the threshold P) without a similar increase in the differential current (multiplier q) signifies an external fault. The dropout timer (DPO) ensures security throughout the fault duration.

The logic of Fig. 14 works satisfactorily for considerable fault currents threatening ac saturation of CTs. A separate path is incorporated in the EFD logic to monitor the amount of the dc components in the currents and engage extra security measures if significant and long-lasting dc components threaten dc saturation of CTs. The dc saturation detection path works even under small fault currents or switching events. The dc saturation detection path is quite beneficial, particularly when high X/R ratios in system impedances are expected, such as when switching reactors or in lines close to generating stations.

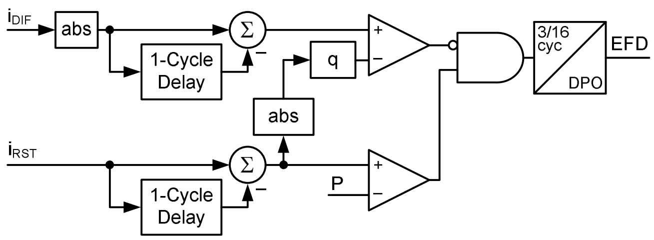

Fig. 14. EFD logic (ac path).

The EFD logic detects external faults and events, yielding high and slowly decaying dc components in the currents. As such, it triggers before any of the zone CTs actually saturate, allowing excellent security of protection. Upon an EFD trigger, the 87L elements can increase the restraining means, such as the following:

- Automatically adjusting settings to be more secure.
- Boosting the restraining signals with harmonics from the differential current.
- Using phase signals for restraining the sequence differential elements, or a combination thereof.

In any case, the EFD logic allows reducing the amount of permanent restraint and therefore considerably increases the sensitivity of line current differential protection.

E. Charging Current Compensation

With reference to Fig. 15, a multiterminal line draws a charging current through its distributed capacitances. The exact distribution of this current depends on the line and system parameters, as well as the voltage profile along the line and its segments. Higher voltages draw larger charging currents. Open-ended lines develop an overvoltage at the open end while not drawing any current from that end. During faults (internal or external), voltages change and become unbalanced, causing changes in the charging current, with the charge flowing out and into the line.

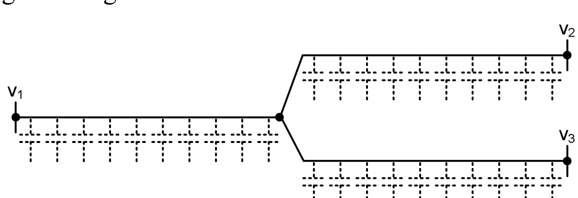

Fig. 15. Distributed capacitance model of a three-terminal line.

From the differential protection point of view, the total charging current (not contributions from individual line terminals) is of primary interest. If so, the total line-charging current can be well approximated as a current drawn by the total line capacitance under the average line voltage. The capacitance is known and becomes a user setting. The voltage can be well approximated from the measured line terminal voltages.

With reference to Fig. 16, the line capacitance can be represented by a lumped parameter model at each terminal of the line.

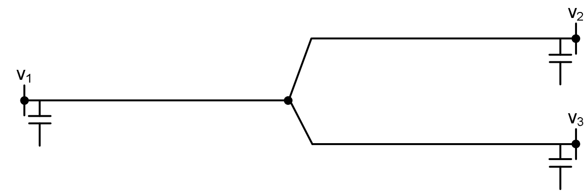

Fig. 16. Lumped parameter model of a three-terminal line.

One solution uses each local voltage to calculate the total charging current in order to subtract it from the measured differential:

$$i_{C\_TOTAL} = C_{TOTAL} \bullet \frac{d}{dt} v_{AVERAGE} \tag{10}$$

or:

$$i_{C\_TOTAL} = C_{TOTAL} \bullet \frac{1}{3} \bullet \frac{d}{dt}\left(v_1 + v_2 + v_3\right) \tag{11}$$

Based on (11), each relay uses a portion of the total capacitance and its local voltage to calculate and subtract a portion of the total charging current. The net effect is that the total line-charging current is based on the average voltage profile of the line and is effectively subtracted without the need to communicate individual voltages between the line terminals.

A practical three-phase implementation uses the following principle and works for transposed and untransposed lines:

$$\begin{bmatrix} i_A \\ i_B \\ i_C \end{bmatrix}_C = \begin{bmatrix} C_{AA} & C_{AB} & C_{AC} \\ C_{BA} & C_{BB} & C_{BC} \\ C_{CA} & C_{CB} & C_{CC} \end{bmatrix} \bullet \frac{d}{dt} \begin{bmatrix} v_A \\ v_B \\ v_C \end{bmatrix} \tag{12}$$

Phase currents are directly compensated using (12), benefiting the 87LP function. Sequence currents are compensated through the compensation of the phase currents, further improving the sensitivity of the 87LQ and 87LG elements. Benefits of line-charging current compensation are most evident during line energization, as illustrated in Fig. 17.

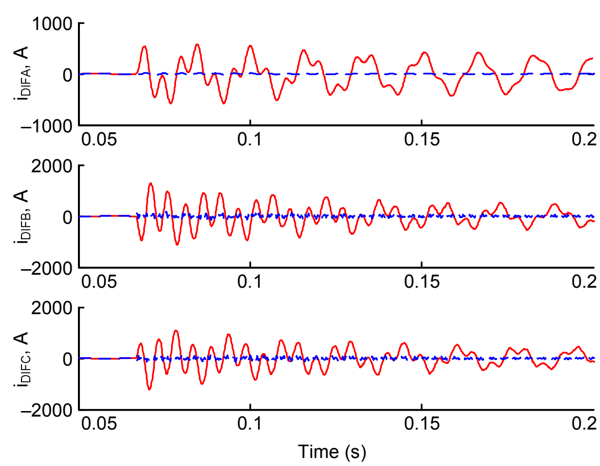

Fig. 17. Example of line energization: differential current without (solid line) and with (dashed line) charging current compensation.

Long lines that benefit from the charging current compensation of the 87L elements often have shunt reactors installed. The capacitive current of the line and the inductive current of the reactors do not cancel transiently as far as fast protection is concerned. The transient nature (frequency response) is different between an inductor and a capacitor, their positive- to zero-sequence reactance ratios can be different, and reactor saturation makes the inductance nonlinear. In addition, reactors are switched on and off as a part of voltage/reactive power control in the power system and can be operated in an unbalanced way (one or two phases).

In order to keep protection applications simple, the reactor current is typically taken out of the measuring zone by paralleling its CTs with the line CTs. At any given time, the line may or may not be compensated, but the 87L element always measures the entire charging current and compensates for it.

With reference to Fig. 18, when applying line-charging current compensation, the line differential zone excludes both the reactors and the charging current itself.

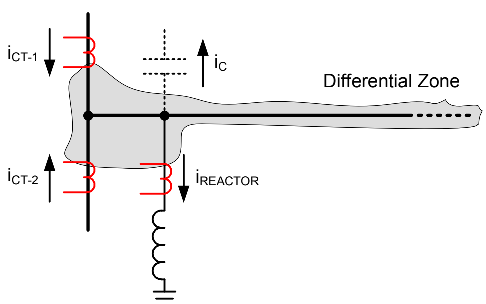

Fig. 18. Line reactors and line capacitance are removed from the differential protection zone.

Excluding line reactors from the differential zone allows much better sensitivity of protection by avoiding several challenges, such as magnetizing inrush current or a grounding point within the zone that would create a zero-sequence path for mutual coupling.

F. Impact of 87L Supervisory Functions

Line current differential relays typically include the following supervisory functions:

- Disturbance detector to guard against undetected data errors due to induced noise and failing components in the communications chain.
- Fault identification logic to aid single-pole tripping applications. The 87LQ and 87LG functions lack the ability to detect the fault type, and the 87LP function may fail to pick up in some of the faulted phases.
- CT trouble (open CT) logic to guard against false differential signals due to problems with wiring, test switches, and relay input circuitry.

The disturbance detection and phase identification elements are used as permissive elements, and therefore, their sensitivity impacts the overall sensitivity of the line current differential protection. The CT trouble element is used as a blocking element, and its sensitivity impacts the overall security of protection.

Disturbance detection can be made very sensitive—this function does not need to distinguish between faults and switching events, is nondirectional, and has no reach accuracy requirements.

One solution uses incremental changes in symmetrical currents and voltages with an adaptive threshold, as depicted in Fig. 19.

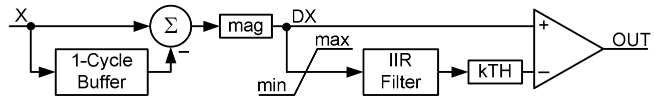

Fig. 19. Disturbance detection algorithm.

The input single X is a current or voltage phasor. A one-power-cycle difference is created to eliminate the impact of load or system unbalance and other errors that tend to cancel out in the cycle-to-cycle differences. A slow infinite impulse response (IIR) filter is used to measure the standing noise in the operating signal DX (ideally zero). The output asserts if the operating signal exceeds a multiple of the standing noise (k_{TH} = about 2 to 3). This algorithm is very sensitive and will respond to high-resistance faults. The algorithm is run in parallel on sequence currents and sequence voltages. The latter are used to ensure positive response at weak line terminals.

Fault identification logic in line current differential functions responds to phase relationships between the sequence components of the differential currents. This method is accurate, fast, and sensitive when applied to line terminal currents in line distance relays. When applied to differential signals, it performs even better and does not penalize the high sensitivity achievable through the 87LQ and 87LG elements.

VII. Sensitivity During Power Swings

A power swing is a variation in power flow that occurs when the generator rotor angles are advancing or retarding relative to each other in response to changes in load magnitude and direction, line switching, loss of generation, faults, and other system disturbances. Power swings can considerably reduce the voltage at the line terminals, considerably increase line currents, and slightly change frequency. As a result, power swings can pose both security and dependability problems for many of the line protection functions.

As is well known, elevated power swing currents and depressed voltages can resemble fault conditions and therefore jeopardize the security of distance, undervoltage, and overcurrent functions. Changes in frequency can reduce the accuracy of polarization and directional methods that rely on memorized values of the polarizing quantities.

What is less obvious is that during power swings, the sensitivity or broader dependability of many protection functions is reduced, even if these functions are left unblocked. This is particularly true during severe or unstable swings.

If during a line fault, the equivalent systems are virtually 180 degrees out of phase with each other, they will feed the positive-sequence currents toward an internal fault. These currents are also 180 degrees out of phase with each other, making the fault appear external. This current flow pattern can impact the dependability of many protection functions that use phase quantities.

In general, the following issues impact dependability during power swings:

- Directional elements may not perform well during power swings. For example, during an unstable power swing, it is challenging to detect the direction of a three-phase fault. Negative-sequence directional elements will be affected if there is a pre-existing system unbalance (e.g., open pole or considerable asymmetry in the line parameters).
- Line terminal currents due to power swings may reach a value of a few times CT nominal and may flow considerably out of phase, creating similar effects as the load current during no-swing conditions. This includes, for example, an infeed/outfeed effect for distance functions or extra restraint for differential functions.
- Memory polarization or usage of incremental protection quantities may cause problems—the memorized values reflect positions of the equivalent sources from the past while the protected system swings, changing its angular position.

Increased dependability during power swings can be achieved through the combination of the following:

- Canceling the block from the power system blocking element upon detecting a fault during a power swing.
- Depending on negative-sequence elements to detect unbalanced faults.
- Depending on phase distance elements with time delays to detect three-phase balanced faults. These elements can be quadrilateral with narrow blinders to allow better ride through for a swing entering the characteristic.
- Depending on nondirectional distance elements with time delays to ensure detection of close-in faults, particularly three-phase faults during unstable swings.

The application of the above measures to regain dependability during power swings may result in decreased security and unintended operation for external faults.

In many instances, the decrease in sensitivity and dependability is temporary. When the stable swing subsides or the unstable swing reaches a point of the sources being in synchronism, many protection functions will operate within their specifications.

VIII. Conclusions

In this paper, we took a fresh look at the limits to the sensitivity of line protection. High sensitivity of line protection can be achieved by the application of elements based solely on negative- and/or zero-sequence quantities. Dealing with spurious negative- and/or zero-sequence quantities in order to retain security without erasing the original sensitivity is critical when designing and applying these sensitive protection elements.

Line characteristics have been reviewed in reference to unbalance and its potential impact on ultra-sensitive protection elements based on negative- and zero-sequence quantities. Even when perfectly transposed, actual lines are unbalanced when considering sections between the internal fault point and the line terminals. This unbalance limits the sensitivity of protection, even if it does not jeopardize security for the protection of healthy lines.

Various aspects of the accuracy of instrument transformers have been discussed in terms of transient and standing errors. Several means of dealing with instrumentation errors have been outlined to aid sensitive line protection.

The sensitivity of directional elements applied as time-coordinated elements or in directional comparison schemes, as well as distance elements and line current differential elements, has been discussed in detail.

Distance elements, both mho and quadrilateral, have limited sensitivity to high-resistance faults. Advanced polarization methods for the reactive and resistive blinders allow the quadrilateral elements to respond to higher fault resistances compared with the mho elements, particularly for faults close to the reach point. Still, the achievable sensitivity is much lower compared with the directional and differential elements based on sequence components.

The dependability of protection, including sensitivity, during power swing conditions has been discussed as well. Several approaches to maintaining protection dependability during power swings have been discussed.

IX. References

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X. Biographies

Dr. Edmund O. Schweitzer, III is recognized as a pioneer in digital protection and holds the grade of Fellow of the IEEE, a title bestowed on less than one percent of IEEE members. In 2002, he was elected a member of the National Academy of Engineering. Dr. Schweitzer received his BSEE and MSEE from Purdue University, and his PhD from Washington State University. He served on the electrical engineering faculties of Ohio University and Washington State University, and in 1982 he founded Schweitzer Engineering Laboratories, Inc. (SEL) to develop and manufacture digital protective relays and related products and services. Today, SEL is an employee-owned company, which serves the electric power industry worldwide, and is certified to the international quality standard ISO-9001.

Normann Fischer received a Higher Diploma in Technology, with honors, from Witwatersrand Technikon, Johannesburg in 1988, a BSEE, with honors, from the University of Cape Town in 1993, and an MSEE from the University of Idaho in 2005. He joined Eskom as a protection technician in 1984 and was a senior design engineer in the Eskom protection design department for three years. He then joined IST Energy as a senior design engineer in 1996. In 1999, he joined Schweitzer Engineering Laboratories, Inc. as a power engineer in the research and development division. Normann was a registered professional engineer in South Africa and a member of the South Africa Institute of Electrical Engineers. He is currently a member of IEEE and ASEE.

Bogdan Kasztenny is a principal systems engineer in the research and development division of Schweitzer Engineering Laboratories, Inc. He has 20 years of experience in protection and control, including his ten-year academic career at Wrocław University of Technology, Southern Illinois University, and Texas A&M University. He also has ten years of industrial experience with General Electric, where he developed, promoted, and supported many protection and control products. Bogdan is an IEEE Fellow, Senior Fulbright Fellow, Canadian member of CIGRE Study Committee B5, and an adjunct professor at the University of Western Ontario. He has authored about 200 technical papers and holds 16 patents. He is active in the IEEE Power System Relaying Committee and is a registered professional engineer in the province of Ontario.

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