Transmission Line Setting Calculations – Beyond the Cookbook

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***Abstract*—Setting transmission line relays is fairly easy to learn—but takes years to master. With the proper education, tools, and references such as company standards available, a relatively inexperienced engineer can do good work with proper supervision and review. There are many references and training programs that provide the high-level basis for protective element setting criteria. But, the concepts have to be applied with care in context of the particular transmission line and system in question. The transmission network is complex, with many variations that must be identified to determine when deviations from cookbook guidelines are required. This paper looks at various commonly used transmission line protective elements and points out characteristics of the line and system to look for when standard reaches and margins cannot be used. While the subject is vast, the authors draw on their experience to point out some of the more common issues.**

I. Introduction

This paper provides a reference for inexperienced and experienced engineers alike to identify characteristics of the transmission line and system that should be considered in calculating settings for transmission lines. It helps readers understand the background and philosophies driving company standard calculations. It also helps readers identify when they need to look beyond these cookbook guidelines.

II. Relay Setting Fundamentals

The objectives should be defined when discussing the effectiveness of a relaying scheme. There are several terms used to define various aspects of relaying scheme performance and reliability.

A. Defining Performance

The performance of a relay element or relaying scheme is described using the terms selectivity, speed, and sensitivity. These are more commonly known as the three Ss. Selectivity is a measure of how well a relay element can differentiate between an in-zone and an out-of-zone fault. Selectivity is inherent in the type of element. Overcurrent elements require branch impedance and/or time to achieve selectivity. Directional overcurrent elements improve on this by only responding to faults in one direction. Distance elements enhance selectivity further by being both directional and having a defined reach in terms of impedance. The most selective, however, are differential elements because their boundaries can be precisely matched to their zones of protection.

Speed is simply a measure of how fast a relay operates for faults, in-zone or otherwise. Speed is an important part of relay performance because it is needed to minimize voltage sag effects, minimize equipment damage, improve safety, and preserve system stability. Speed can be impacted by inherent delays and intentional time delays. Even if a relay element delay is set to 0 cycles, it cannot truly operate instantaneously. The element takes some time to make a decision, and the relay operates faster if the multiple of pickup for a particular fault condition is higher. Intentional delays can be used to coordinate with other relays or to ride through transient conditions. See Table I for the levels of definite-time delay used for primary protection. Speed is also directly related to selectivity. More selective elements can be set with low or no intentional delay, while less selective elements must rely on a delay to coordinate with remote relays.

TABLE I
LEVELS OF DEFINITE-TIME DELAYS FOR PRIMARY PROTECTION

Level	Delay (cycles)
No intentional delay	0
Delay for block signal	1−2
Delay for fault clearing	8−12
Delay for fault clearing with breaker failure	18−24

Sensitivity is a measure of the ability of the relay to pick up for in-zone faults. It affects how the relay performs under minimum source conditions, for high-resistance faults, and for low-grade faults. Sensitivity is related to selectivity as well. Distance and overcurrent elements that are set more sensitive are less selective and vice versa. Selectivity, speed, and sensitivity need to be balanced to produce a relaying scheme that is reliable.

B. Defining Reliability

The reliability of a relaying scheme is more precisely defined using the terms dependability and security. Dependability is the ability of a scheme to operate for any in-zone fault. Security is the ability of a scheme to not operate when there is no in-zone fault. They are usually inversely related, but better schemes can raise both to improve overall reliability. Security is challenged every time faults occur in adjacent zones of protection, but dependability is only challenged when the fault is in-zone.

According to the North American Electric Reliability Corporation (NERC) Misoperations Report, approximately 94 percent of misoperations resulted in false trips [1]. False trips indicate a bias toward dependability, whereas failures to trip indicate a bias toward security. Traditionally, transmission line relaying schemes are designed with a dependability bias to avoid failures to trip or slow trips. This is because power systems generally tolerate the loss of additional elements better than uncleared faults. To further promote dependability, they are designed with redundant protection systems and they can rely on automatic reclosing to put unfaulted elements back in service. Efforts to reduce misoperations can improve overall reliability by reducing false trips without increasing failures to trip by sacrificing dependability.

C. *Reducing Misoperations*

The Protection System Misoperations Task Force (PSMTF) made several recommendations to improve protection quality by reducing misoperations [1]. False trips can be reduced by properly applying and coordinating relay elements, reducing settings errors, and improving pilot scheme performance. Failures to trip can be reduced by prioritizing critical firmware updates and by monitoring the alarm contacts of numerical relays to detect relay failure. Fig. 1 shows the top three causes of misoperations and the conditions when each occurred. Note that false trips dominate the chart.

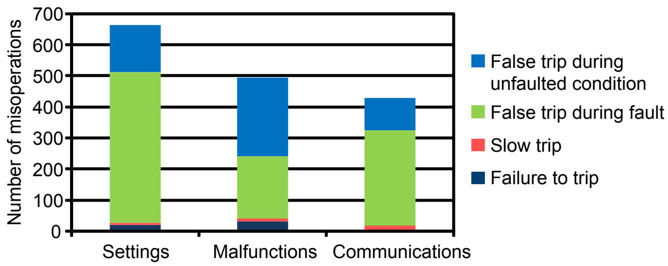

Fig. 1. Chart of top three causes of misoperations and the conditions when each misoperation occurred.

When relay elements are not applied appropriately, it can lead to misoperations. Coordination cannot be properly conducted between elements that operate on functionally different quantities, for example, coordinating between distance and overcurrent elements or between dissimilar directional polarization methods. Even coordinating between overcurrent elements that use different measurement techniques should be conducted with caution.

Settings errors can be reduced by making improvements to the engineering process. Increased training and peer reviews can improve the quality of settings produced. Also, standardized settings templates can be used to improve consistency in standard applications. Lastly, existing settings should also be reviewed in the event of system topography changes to ensure that they are still applicable.

While it is not the focus of this paper, steps can also be taken to improve pilot scheme performance. Channel reliability can be improved by migrating to more robust communications media or improving maintenance on power line carrier equipment. New technologies can be used to ride through temporary signal losses as well. In addition, the differences in speed must be accommodated when using mixed relay technologies, such as when coordinating numerical and electromechanical relays. Although the NERC Misoperations Report mentions accommodating different operating speeds between different relay technologies in a communications-assisted scheme, it is important to realize that it is not possible to completely ensure the sensitivity coordination of dissimilar relays. That is, a pilot tripping element and its associated remote pilot blocking element in dissimilar relays will not respond in the same way to an extreme boundary fault [2].

III. Relay Coordination

A. *The Art and Science of Line Protection*

All five aspects of performance and reliability are interrelated. Every element setting affects performance (selectivity, speed, and sensitivity) as well as reliability (dependability and security). Therefore, performance affects reliability and vice versa.

In general, relay engineers have two “knobs” to adjust when creating settings for a protective element in a relay: sensitivity and delay. Raising the sensitivity of an element improves dependability but reduces security. Shorter delays for relay elements improve performance, but they also reduce security. As a rule, this means that elements should be set fast but not too fast, and they should be set sensitive but not too sensitive. Interpreting this tongue-in-cheek expression of the relay setting engineer craft, this means most settings have two limits: a dependability limit and a security limit. Misoperations can occur when a relay engineer focuses on one limit without considering the other. It is common for relay engineers to focus on dependability—always clearing the fault. This is one reason that the statistics show a vast majority of misoperations as false trips.

The science of relaying is about calculating the dependability and security limits. The art of relaying is about the effective application of margins to these limits. The final setting selected should lie between these limits with margin. The sizes of these margins are based on the accuracy of the calculations and the precision of the relay elements themselves. In case of conflicts, the engineer needs to evaluate which margins can be sacrificed and which should not.

B. *Contingencies and Infeed*

The power system needs to operate at all times, so it has generally been designed to survive the loss of any single element or component. This is known as a single contingency or N − 1 condition. The power system is also designed to survive high-probability double contingencies (N − 2), where two elements are out of service. Power system protection must maintain reliability under both of these conditions. Common contingencies include strong sources being taken out of service, parallel lines being taken out of service, the loss of pilot protection, and remote sources being taken out of service. When coordinating distance and overcurrent elements, it is common for high probability double contingency cases (N − 2) to include a loss of pilot protection as one of the two contingencies.

If a source is taken offline with some regularity, as is common with wind farms or peak power generation, then they should be considered alternate normal conditions. They would not qualify as contingencies. Thus, when looking for a minimum source condition, the intermittent source would be taken out for an alternate normal and then another network element would be taken out of service for the $N-1$ contingency. Then, when looking for a maximum source condition, the intermittent source would be returned to service along with all other network elements on the bus that are behind the relay for the $N-0$ condition.

Determining $N-0$ and $N-1$ conditions requires knowledge of how the transmission system is operated and comes with experience. When the authors are reviewing calculations prepared by junior engineers, the authors most often challenge the contingency assumptions that the engineer made when calculating a particular security or dependability limit for a setting.

Different contingencies can affect the level of current that the protective relay measures, and they can cause the presence or absence of sequence quantities. Changes to infeed can affect the apparent impedance to the fault. Higher levels of infeed at the remote substation improve selectivity and aid coordination with remote relays, but they also harm the ability of the local relay to act as a backup in the event of a failure at the remote substation. Understanding the role that infeed plays in affecting relay sensitivity can help identify the contingencies appropriate for checking the dependability limits or security limits. Fig. 2 illustrates the impact of infeed, and (1) shows how the apparent impedance is greater with infeed.

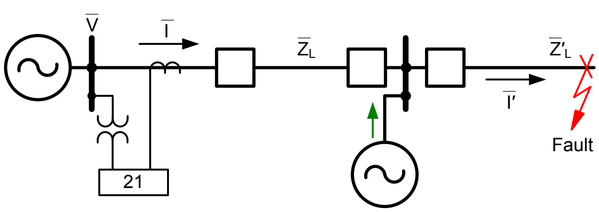

Fig. 2. One-line diagram illustrating the infeed effect.

$$\begin{aligned} \overline{V} &= \overline{I}\overline{Z}_L + \overline{I'}\overline{Z'}_L \\ \overline{Z} &= \frac{\overline{V}}{\overline{I}} = \overline{Z}_L + \frac{\overline{I'}}{\overline{I}}\overline{Z'}_L > \overline{Z}_L + \overline{Z'}_L \end{aligned} \tag{1}$$

Sometimes, reducing infeed creates the worst-case condition, and there are other times when increasing infeed produces the worst-case condition for a different check. It is important to note that there is no single worst-case condition for all relay elements.

Elements that underreach the end of the protected zone can be set with no delay because they do not have to coordinate with remote relays. However, they must underreach under every normal condition, single contingency, and high probability double contingency. Underreaching elements cannot provide complete protection for a zone alone, so overreaching elements are used as well. Elements that overreach the end of the zone of protection must rely on a time delay or signaling to be selective. Both the time delay and communication require coordination with remote relays. Just as the underreaching elements must underreach under contingency, the overreaching elements must overreach under contingency.

C. Short Circuits

Protection schemes must be designed with consideration given to the four types of faults shown in Fig. 3.

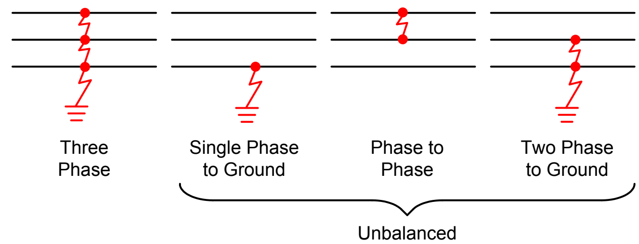

Fig. 3. Illustration of the four fault types.

Protection schemes are designed around the differing dependability and security concerns for phase and ground faults. Relay elements that can operate for balanced phase faults need to be set to avoid limiting the loadability of the protected line. The power system is built for positive-sequence load flow, so there is less of a change in fault current with distance. This means that phase overcurrent elements are less selective, so they are not ideal for phase fault protection.

Distance elements are sufficient for phase fault protection because fault resistance is not a concern. The reason the authors mention fault resistance here is because a mho distance element inherently has less reach as the apparent impedance of the fault moves from the line angle near the X axis closer to the R axis. Overcurrent elements do not have this characteristic, so they tend to provide better accommodation for fault resistance. However, unlike ground faults where the fault loop can contain significant resistance due to tower footing resistance and the nature of the ground return path, the only cause of additional resistance for a phase fault is the arc itself, which is usually not significant. Reference [3] provides an empirical equation for estimating the resistance of the arc.

Table II shows that ground faults are the most common type of fault [4]. Engineers setting ground elements do not need to be concerned with balanced load flow, so the elements can be set sensitive. However, there is more uncertainty in the zero-sequence network model, so larger margins may be required.

TABLE II
FAULT TYPE DISTRIBUTION IN HIGH-VOLTAGE TRANSMISSION SYSTEMS

Fault Type	Distribution (%)
Phase to ground	70
Phase to phase	15
Phase to phase to ground	10
Three phase	5

The zero-sequence line impedance is greater than the positive-sequence line impedance, so there is more of a change in zero-sequence fault current with distance. This property improves the selectivity of zero-sequence overcurrent elements. In addition, high-resistance faults are more common with ground faults than with phase faults, so the use of overcurrent elements is encouraged. Traditionally, slow operating speeds for ground faults were considered acceptable because they had less of an impact on stability and power quality. However, ground faults do have a higher impact on public safety, so sacrifices to speed still come with a cost.

IV. Transmission Line Relay Schemes

There are a few common approaches to protecting the whole length of a given transmission line. Step distance schemes rely on timing and coordination, not communication, to differentiate between internal and external faults. Communications-assisted schemes are able to achieve faster speeds than step distance alone by using signaling between the relays at each terminal of a transmission line to differentiate between internal and external faults. Directional pilot and line current differential are common examples of these communications-assisted schemes.

Step distance schemes can provide transmission line protection without the use of communication. This enables them to back up communications-assisted schemes in the event that communication is lost. They use a combination of underreaching elements with no intentional delay and overreaching elements with a coordination delay. The time-delayed overreaching elements can also provide backup protection for adjacent zones. The distance elements are supplemented with ground overcurrent protection to provide sensitivity to high-resistance ground faults. The sensitive overcurrent elements are typically used with an inverse timing curve. Because this scheme relies on significant time delays to achieve selectivity, it is not able to provide high-speed tripping for the full length of most transmission lines.

Directional comparison protection is a communications-assisted protection scheme designed to provide high-speed tripping for faults anywhere on the protected line. They use signaling to provide selectivity for overreaching elements, which enables them to trip at a high speed. Fig. 4 shows the relay connections involved for these types of schemes. Pilot protection can be divided into permissive or blocking schemes based on what they use their signal for.

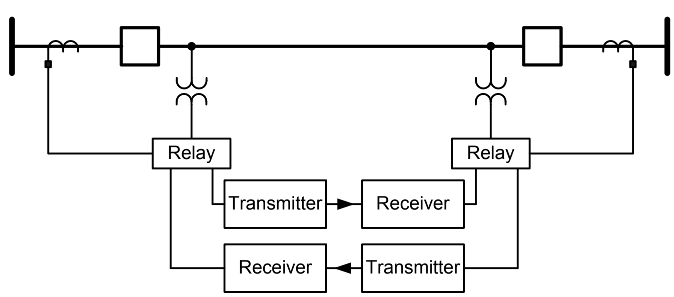

Fig. 4. Connections for a pilot protection scheme.

Blocking schemes, such as directional comparison blocking (DCB), send a blocking signal when the fault is behind the relay. If a relay in a DCB scheme picks up a fault in the forward direction and it does not receive a blocking signal within 1 to 2 cycles (see Table I), then the relay trips as shown in Fig. 5. Each relay in this scheme requires tripping and blocking elements.

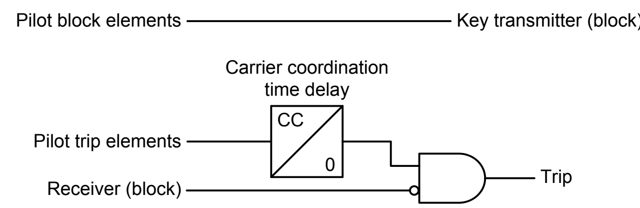

Fig. 5. Basic DCB logic.

Permissive schemes, such as permissive overreaching transfer trip (POTT), send a permissive signal when the fault is in front of the relay. If a relay in a POTT scheme picks up for a fault in the forward direction and it receives a permissive signal from the remote relay, then it trips as shown in Fig. 6. Classic POTT schemes only required tripping elements, but modern versions of POTT schemes (hybrid POTT schemes) add blocking elements that prevent the transmission of the permissive signal for a short time after a reverse fault is detected. This covers for current-reversal scenarios and prevents the relay from echoing a permissive signal.

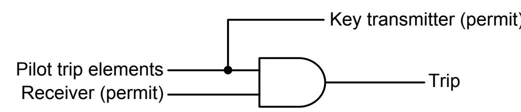

Fig. 6. Basic POTT logic.

Both blocking and hybrid permissive schemes require the pilot blocking elements to be coordinated with pilot tripping elements. Distance and overcurrent elements can be used together in a pilot scheme, but they each must be coordinated with elements of the same type. Fig. 7 shows a pilot scheme that has its tripping and blocking elements properly coordinated. The blocking element of a relay needs to be set more sensitive (longer reach) to faults behind it than the tripping element of the remote relay. The coordination process is easier for overcurrent elements because both relays see approximately the same current for external faults (the current entering the line at the remote terminal is the same current exiting the line at the local terminal for a fault behind the local terminal).

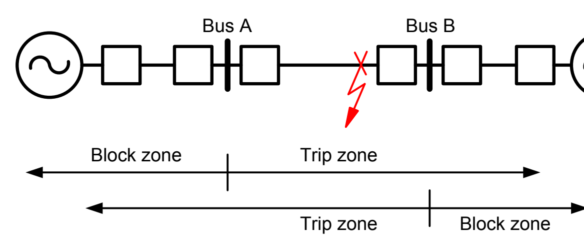

Fig. 7. Example one-line diagram for a pilot protection scheme.

Line current differential is a communications-assisted scheme that differentiates between internal or external faults by comparing the line currents measured by the relays at each terminal. There is minimal coordination required beyond ensuring that the current transformer ratio (CTR) information is entered correctly and that the relays are properly set if dissimilar CTRs are used. In the event that communications are lost between the relays, a step distance scheme can also be implemented to provide backup. The same is true of the other communications-assisted schemes. Modern numerical relays have the capability to implement both types of schemes in the same device, and it is recommended to do so for any communications-assisted scheme.

V. Starting Calculations

Relay setting calculations may have more than 20 years of life, so it is necessary for the relay engineer to thoroughly document the reasoning behind the settings with added notes. Relay calculation templates help engineers do good work, but the engineer must own every word and calculation in the document.

There are several approaches for making relay setting calculations. One approach is to calculate a setting and then do a number of checks to verify that the calculated setting is acceptable. Another approach is to format the calculations such that the setting engineer calculates both dependability limits and security limits for each element and then selects a setting that is in between these two limits. The authors prefer the latter approach because it forces the engineer to choose a setting instead of letting an equation provide a number that they may blindly apply. And, by always calculating the upper and lower limit for the acceptable range, it forces the engineer to balance dependability and security when choosing a setting.

Before beginning the calculations for the protection settings, a CTR must be selected and key information about the system must be calculated.

A. CTR Selection

There are several factors to consider when selecting a CTR. The CTR must be high enough to handle the NERC requirement of 150 percent maximum emergency line rating. Most CTs are thermally rated so they can carry a load greater than the nominal current rating, and that thermal rating should be taken into account during CT selection. CT saturation should also be considered when selecting a ratio [5]. CTs can saturate when the selected turns ratio is too low for the fault currents applied to the CT. It can impact both the performance and reliability of the relay if the saturation is severe enough. As a rule of thumb, CT saturation should be evaluated if less than half of the turns are used or if the fault current is greater than 20 times its nominal rating.

If the CTR is set too high in an attempt to avoid overloading or saturation, then it can have a negative impact on the overall sensitivity of the relay. The rule of sensitive but not too sensitive applies here. Also note that matching the CTRs at both terminals makes coordination easier for communications-assisted protection schemes. There are several fault detectors set in secondary amperes that the engineer needs to be aware of to ensure that the sensitive pilot elements are coordinated. The CT selection process requires the engineer to balance thermal loading, accuracy, sensitivity, and coordination needs.

B. Source Impedance Ratio

The source impedance ratio (SIR) is a voltage divider measure that provides the voltage seen by the relay for an out-of-zone fault [3] [6]. Voltage restrains impedance-based elements, so a low voltage at the relay for an out-of-zone fault increases the impact of error and transient overreach. SIR is best calculated using (2) by simulating a fault at the boundary of the zone of protection, as shown in Fig. 8.

$$Z_{SX} = \frac{V_{DROP\_SRC}}{I_{RELAY}} = \frac{V_{BASE\_LN} - V_{RELAY}}{I_{RELAY}} \tag{2}$$

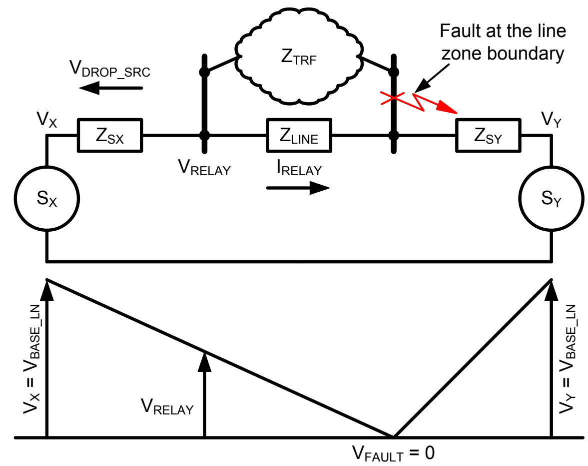

Fig. 8. One-line diagram showing how to calculate SIR.

A line with an SIR above 4 is electrically short, and this does not always correspond to physically short lines [3]. From an electrical perspective, a line can appear short from one terminal but not from the other. It is also possible for a line to be short under N − 1 but not under N − 0. Calculating SIR for both system normal (N − 0) and N − 1 is recommended because it enables the engineer to be more aware of system topology.

Traditionally, the Zone 1 instantaneous distance element has its margin increased for moderately short lines or disabled for extremely short lines to avoid overreach. However, modern relays have features that allow them to ride through the capacitance-coupled voltage transformer (CCVT) transients seen on lines with high SIRs [7]. It is recommended to use these features for any short line where Zone 1 is applied. However, these relay functions have a limit on how high of an SIR they can tolerate. To prevent overreach, Zone 1 needs to be disabled when the calculated SIR exceeds the SIR limit of the relay.

C. NERC Loadability

Step distance Zone 3 trips during stressed system conditions are a classic example of relay setting engineers not calculating a security limit when making their setting. Because of this, NERC now mandates loadability limits. NERC loadability criteria define a mho circle that goes through the following load point: 150 percent of the four-hour emergency rating at 85 percent of the system voltage, and a 30-degree power factor angle [8]. The reach of the associated loadability circle can be calculated using (3), (4), and (5). Equation (3) calculates the apparent power of the NERC load point. Equation (4) calculates the magnitude of the load impedance in secondary ohms. Equation (5) calculates the reach of a mho circle passing through the NERC load point. The maximum torque angle (MTA) in (5) is set to the line angle. Fig. 9 shows the result of these loadability circle calculations.

$$S_{NERC\_LOAD} = \sqrt{3} \bullet (0.85 \bullet kV_{LL}) \bullet (1.5 \bullet I_{4Hr\_Limit}) \quad (3)$$

$$Z_{NERC\_LOAD} = \frac{(0.85 \bullet kV_{LL})^2}{S_{NERC\_LOAD}} \bullet \frac{CTR}{VTR} \quad (4)$$

$$Z_{NERC\_REACH} = \frac{Z_{NERC\_LOAD}}{\cos(MTA - 30°)} \quad (5)$$

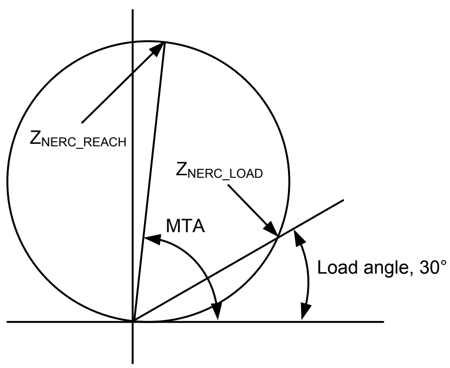

Fig. 9. A mho circle showing the maximum reach for a given NERC load point.

Traditionally, VARs are considered a function of load at a power factor. However, watt and VAR flow can be decoupled in the transmission system during a disturbance. The power factor angle is a poor indicator to differentiate fault from load, which means that there is a limit to what load encroachment can do. A practical limit to the reach of mho elements with load encroachment is two times the maximum NERC reach limit. Fig. 10 shows a mho element that is set to the NERC loadability reach limit (blue). If relay setting engineers need to set a reach larger than this limit, they are required to apply a load encroachment element (green). The red circle represents a mho element set to two times the NERC reach limit.

The evidence of a practical limit to load encroachment is more apparent in Fig. 11, which shows the same example plotted on the PQ plane. In Fig. 11, the total shaded area is the safe load flow area. To the right of the green line, 150 percent of the four-hour emergency rating of the line is exceeded, and NERC allows tripping in that area. Above the blue line is inside the maximum allowable mho element reach and NERC allows tripping in that area.

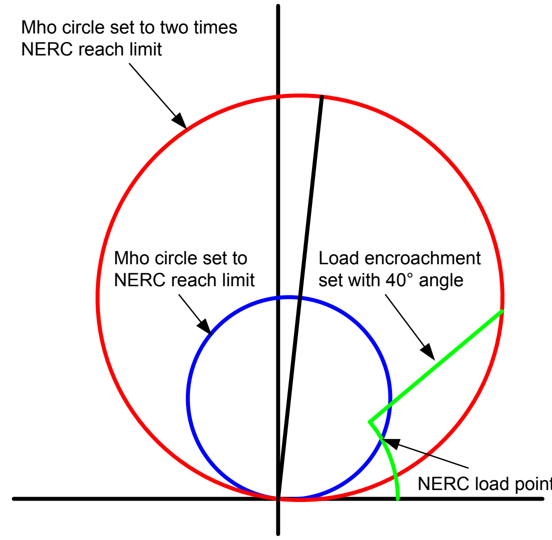

Fig. 10. Load encroachment characteristic with margin on RX plane.

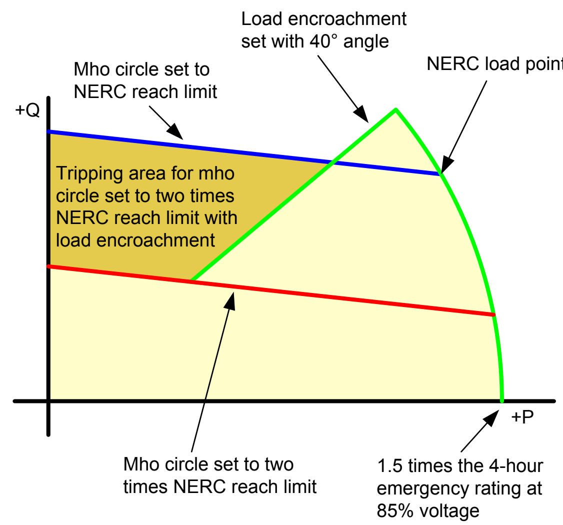

Fig. 11. Load encroachment characteristic with margin on PQ plane.

The darkly shaded area in Fig. 11 is the additional area carved out of the line loadability where the mho element set to two times the NERC maximum reach will trip on load flow. As the reach increases, even when mitigated by using load encroachment, the probability of tripping the line on VAR flow during stressed system conditions increases.

VI. Phase Distance Protection

Relay protective elements are enabled based on the type of fault protection they provide. Phase fault protection is primarily accomplished for transmission lines using phase distance elements. Phase overcurrent protection is generally not recommended for transmission lines because it provides poor long-term selectivity as system source conditions change with time. Changes in source conditions are becoming more of a problem today with the significant changes in the generation patterns happening to the system. And, as mentioned earlier, there is little need for high arc resistance coverage. Supplemental overcurrent elements can be used to cover for scenarios where the distance elements are unable to operate. A loss-of-potential (LOP) condition or a switch on to fault (SOTF) condition are examples of these scenarios. However, the relay logic would disable these phase overcurrent elements during normal conditions.

Phase distance protection can be divided into five distinct zones, each with a different purpose. Three zones are used for step distance schemes: Step Zone 1, Step Zone 2, and Step Zone 3.

- Zone 1 is an underreaching instantaneous element.
- Zone 2 is an overreaching time-delayed element used to cover the rest of the zone of protection not covered by Zone 1.
- Zone 3 is also an overreaching time-delayed element, but it has a longer reach, has a longer time delay, and is used as remote backup.

The other two distance zones are used for pilot protection: the pilot tripping zone and the pilot blocking zone. Because of the limited number of distance elements in some relays, it is common to combine the pilot tripping zone with either Step Zone 2 or Step Zone 3. The pilot blocking zone faces in the reverse direction, and it must be coordinated with the remote relay pilot tripping zone by setting its reach to be more sensitive to reverse faults. If it is set too sensitive, it may block during heavy load conditions and interfere with the normal operation of the pilot scheme.

A. Phase Distance Step Zone 1

Phase distance Step Zone 1 is commonly set to a reach in the range of 80 to 90 percent of the positive-sequence line impedance. This margin is needed to compensate for any measurement error and because transmission lines are typically not physically balanced. For example, flat construction can have a significant difference between phase loops [9]. A margin is also needed because short lines have more error for an out-of-zone fault. Step Zone 1 must never overreach the end of the transmission line because it operates instantaneously.

There are some exceptions to the cookbook rule of 80 to 90 percent. Overreach is not a concern with radial lines because there are no other transmission lines to miscoordinate with. Overreaching distribution buses is typically not a concern due to the high impedance of distribution transformers, so a reach in the range of 120 percent of the line is acceptable. Short lines present another exception. SIRs between 4 and 10 should be able to rely on the relay high SIR functions to avoid problems. Beyond an SIR of 10, it is recommended to start reducing the Zone 1 reach. Ultimately, the Zone 1 element should be disabled if the SIR exceeds the ability of the relay to compensate. This occurs once the SIR gets above 30 or so, but the exact number is dependent on the model of the relay. Individual judgment should be used if the SIR is moderate under N − 0 but high under N − 1. The likelihood of the N − 1 condition should be a factor in the decision on how much margin to use.

Three-terminal lines present another challenge because there are two remote buses to be concerned with, and the apparent impedance between the relay and the remote buses can vary due to infeed. The solution is to base the cookbook value of 80 to 90 percent on the minimum apparent impedance seen for a fault at either of the remote buses. This check should be performed with the unfaulted terminal breaker open and performed again with it closed. This ensures that the distance Step Zone 1 will always underreach either remote bus. This principle of using the minimum apparent impedance for Zone 1 also applies to other conditions that can influence the apparent impedance, such as series-compensated lines. However, some relays may have functions specifically for handling series-compensated lines, so the relay instruction manuals should be followed in those cases.

Relays use overcurrent supervision to ensure that there is a minimum level of fault current before their distance elements can operate. Traditionally, these fault detectors were required to prevent misoperation during an LOP event where a potential transformer (PT) fuse blows and removes restraint from the distance elements. Modern relays include LOP logic that can prevent misoperation by detecting the LOP condition and blocking the distance elements. However, in relays without advanced LOP logic, the LOP logic is not fast enough to block the Zone 1 elements, so fault detectors are still required—at least for the Zone 1 elements [10]. Fault detectors can also be used to prevent operation for extremely weak N − 1 conditions.

When setting relays without advanced LOP logic, the following criteria should be used. For dependability, the pickup should be set below the minimum fault current seen for a balanced fault at Zone 1 reach by a margin of 50 to 67 percent. For security, the pickup should also be set above the winter emergency load rating by a margin of 110 percent if possible. The lowest number of the two thresholds should be used because dependability takes precedence over security in supervisory elements such as these.

Consider the following example. A fault at Zone 1 reach under N − 1 is 2,400 amperes, and the winter emergency rating of the line is 700 amperes. The dependability limit with a margin of 50 percent is 1,200 amperes. The security limit with a margin of 110 percent is 770 amperes. The supervision would be set to 770 amperes because it is the lower of the two limits. There is no need to average the two for a supervising element.

B. Phase Distance Step Zone 2

Phase distance Step Zone 2 is commonly set to a reach in the range of 120 to 150 percent of the positive-sequence line impedance. Others base the Zone 2 reach on the full line impedance plus a percentage of the neighboring line impedance as an additional criterion. Step Zone 2 must always overreach the end of the transmission line to ensure that the whole line is covered. It is intended to protect the portion of the line left unprotected by Zone 1. If there are conditions that affect the apparent impedance of the line, such as a three-terminal line, then the maximum apparent impedance should be used in this calculation. Series-compensated lines would use their uncompensated line impedance.

Zone 2 is set with an 18- to 24-cycle delay (see Table I) to coordinate with remote relays. The remote relays use that time to clear the fault and give breaker failure functions time to operate. Unlike Step Zone 1, there is no LOP race for Zone 2 supervision, so any fault detectors can be set to the minimum level.

Just as with Step Zone 1, there are exceptions to the rule when setting Zone 2. One exception occurs for transmission lines that have branches tapped off of them. The apparent impedance for a fault at the end of a tap may be greater than the total impedance of the transmission line. The infeed from each terminal has an impact on the apparent impedance, so it should be checked during system normal and during single-contingency conditions. Some single-contingency conditions magnify the effect of infeed by reducing the current contribution from the local terminal.

Fig. 12a shows a real-world example of a Step Zone 2 element set to 125 percent of line impedance. The line is 42 miles long and has a number of distribution substations tapped along its length. One of the load tap substations is on a 7-mile lateral at around 26 miles from the local terminal. Fig. 12b marks the apparent impedances seen for a fault at the remote bus at the end of the tap under N − 0 and at the end of the tap under N − 1.

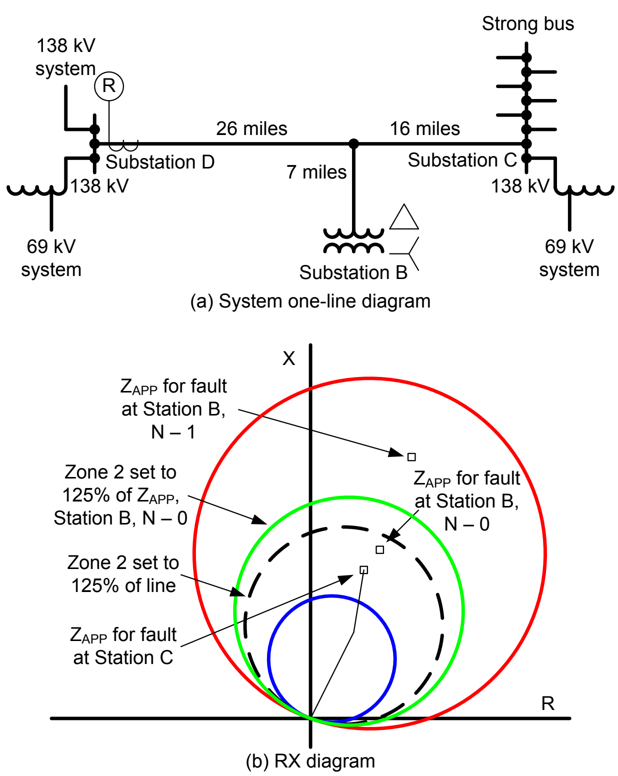

Fig. 12. Zone 2 coordination example using corrected reaches.

The tap N − 0 fault is in Zone 2 with little margin. Note that the apparent impedance (Z_{APP}) is greater than a fault on the remote bus. The apparent impedance seen for an N − 1 fault is in Zone 3 instead. The change in infeed causes a greater apparent impedance under N − 1. Under N − 0, the local terminal supplies 29 percent of the fault current through the tap, but this drops to 13 percent under N − 1.

The taps should be covered with either Zone 1 or Zone 2 during N − 0 conditions. During N − 1 conditions, this fault should be covered by Zone 2 if possible but Zone 3 at the very least. Otherwise, the fault will be cleared sequentially after Substation C opens its terminal. The reaches may need to be adjusted to cover the taps with margin. In this case, a reach of 125 percent of Z_{APP} at Substation B should be applied.

Because Step Zone 2 overreaches the remote bus, it needs to be coordinated with the remote relays. This coordination check is performed even if all remote zones have communications-assisted relaying schemes. The N − 1 condition in those cases is the communications scheme being taken out of service. If a line only has a step distance scheme, N − 1 would remove the largest source of remote infeed instead.

Faults beyond Zone 1 in remote lines will be cleared in their Zone 2 delay. If the local relay Zone 2 element overreaches the remote relay Zone 1 element, then the reach needs to be reduced. Alternatively, the local relay Zone 2 delay could be increased by another 8 to 12 cycles (see Table I) to coordinate with the remote relay Zone 2 delay. Zone 2 coordination is normally only checked with the shortest remote line, but this may not be the worst-case condition. Infeed distribution could result in a longer line appearing shorter. Automated coordination checks are recommended to catch cases such as these. If a step distance Zone 2 element needs to be coordinated with a strain bus line with no Step Zone 1 protection, the delay would normally need to be increased. However, transmission lines with dual 87L protection schemes with redundant communications paths can be considered the same as an 87T or 87B zone. Strain bus lines are typically found where a substation owned by another entity is located very near the utility tap substation. The line is protected using line relays; however, this is only to provide isolation between the protection systems owned by the two separate entities.

Another exception to the cookbook margins can occur when applying Zone 2 to long lines that are adjacent to short lines. Consider the example shown in Fig. 13. There is no Zone 1 protection enabled on the 0.25-mile blue line. For the N − 1 condition where pilot protection is out on the blue line, the critical coordination point is a close-in fault on the blue line. If pilot protection is out on the green line instead, then the coordination point is a fault at the end of the blue line Zone 2 reach.

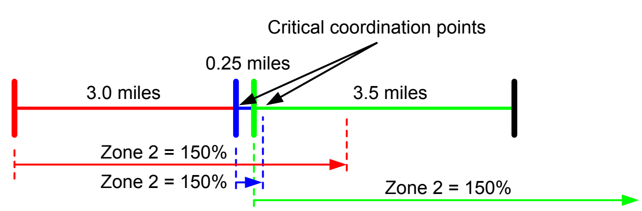

Fig. 13. Zone 2 coordination example using cookbook reaches.

To coordinate with the existing reaches, which are set to 150 percent of each line in this example, the Zone 2 delay on the red line would need to coordinate with the blue line Zone 3 instead because a fault on the green line between the end of the blue line Zone 2 and the end of the red line Zone 2 reach would be sensed by the blue line Zone 3. This would result in excessive delays, and it is an example of not considering that the relay engineer has two "knobs" to adjust. As an alternative, the Zone 2 reach on the blue line can be increased beyond the cookbook value to 1,000 percent, as seen in Fig. 14. Note that when picking the 1,000 percent overreach setting for Zone 2 on the blue line, the authors checked coordination so that the protection did not overreach the Zone 1 on the green line. This approach avoids adding excessive delays because only the Zone 2 timers would need to be coordinated. The blue line Zone 2 reach would be based on the critical coordination points rather than the positive-sequence impedance of the blue line.

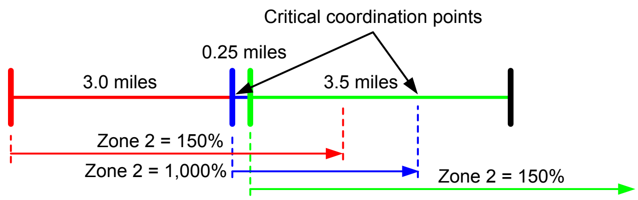

Fig. 14. Zone 2 coordination example using corrected reaches.

For other applications, it may be possible to achieve coordination by reducing the reach of the backup relay. The engineer needs to be mindful of the dependability limit when doing so.

C. Phase Distance Step Zone 3

Phase distance Step Zone 3 is used for backup protection in the event of a failure at the remote bus. Reaches of 200 percent or more of line impedance are common with Zone 3. Just as with Zone 2, it is recommended to use much larger multiples than the cookbook for short lines. Also like Zone 2, Zone 3 must always overreach the zone of protection. If there are conditions that affect the apparent impedance of the protected line, such as a three-terminal line or a series-compensated line, then the maximum apparent impedance should be used in the reach calculation. Zone 3 must be sensitive enough to see the ends of every line tap under $N - 1$ conditions. There is no LOP race for the Zone 3 current supervision setting, so it can be set to the minimum level.

Zone 3 is required to cover for breaker failure at the remote substation whenever remote breakers are shared with adjacent transmission lines or autotransformers. The Zone 3 reach must be set greater than the total impedance of both the protected line and the adjacent branch without infeed. Ring bus and breaker-and-a-half configurations have shared breakers, but shared breakers are not limited to those two configurations. A line terminated in a transformer with or without a breaker separating the line zone from the transformer zone is another common case.

When a breaker fails to operate for a fault, the local breaker failure function opens the breakers adjacent to the affected breaker. This removes infeed to the fault so that it is easier for relays at the remote ends of the affected branches to pick up the fault and clear it. A direct transfer trip (DTT) function can be used in the breaker failure scheme, so Zone 3 would only provide backup via time-delayed clearing. Breaker failure with or without DTT is more common at higher transmission-level voltages. Substations at subtransmission-level voltages may not have any breaker failure function implemented, so infeed will not be removed in those cases.

Step Zone 3 is coordinated with each of the remote relay Step Zone 2 elements. The Zone 3 coordination point is beyond one bus beyond the remote bus: two tiers removed. If the Zone 3 element does not pick up for faults on any of the buses two tiers removed with infeed, then there is no need to check coordination further. If it still picks up, then checking coordination would require faults to be simulated on each line out of the Tier 2 bus. Because Zone 3 is a backup element with a long delay, it may be considered unnecessary to put so much effort into Zone 3 coordination beyond Tier 2 buses. Emphasis is instead placed on time coordination along the length of each remote line because coordination is more likely to be challenged there.

D. Phase Distance Pilot Tripping Zone

The phase distance pilot tripping zone should always overreach the remote bus, but by how much? As mentioned before, the pilot tripping zone is commonly combined with either Zone 2 or Zone 3 because the number of distance elements is limited. Fig. 15 shows an example diagram of the step distance zones and how a fault appears to the relay as it transitions from prefault to fault impedance. In this example, the measured fault impedance first moves inside Zone 3, then Zone 2, and then settles inside Zone 1.

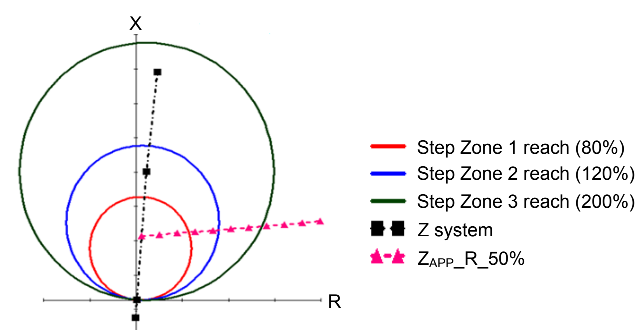

Fig. 15. An impedance diagram showing step distance zones and a newly formed fault.

This means that reusing Step Zone 3 as the pilot tripping zone would allow it to pick up faster for faults, allowing for faster pilot clearing of faults on the transmission line. There are also advantages to using Zone 3 if it provides breaker failure coverage. Local breaker failure functions can stop blocking signals (DCB) or key permissive signals (POTT) to allow high-speed tripping when the pilot tripping zone can see 100 percent of any neighboring zone that shares a breaker with the protected zone. Using Step Zone 2 would be more secure, but it comes with a performance cost.

If the pilot tripping zone uses a dedicated distance element independent of the step distance zones, then the engineer would have more freedom with regard to determining the reach. An independent pilot tripping zone only needs to be coordinated with the remote pilot blocking zone, so it does not need to be adjusted for any issues encountered in step distance coordination. A separate pilot tripping zone also would not be required to cover for remote breaker failure as the step distance Zone 3 element is, except in schemes that use stop carrier as a surrogate for a dedicated DTT channel.

It is recommended to use a reach of 200 percent or more. The pilot tripping reach should be set high enough so that the SIR for the setting itself is less than or equal to 5. This is especially important for reliable high-speed tripping for short line applications [11]. Regardless of the criteria used to calculate the reach, load encroachment is required for any pilot tripping zone that exceeds the NERC loadability reach.

E. Phase Distance Pilot Blocking Zone

The pilot blocking zone must have its reach set so that it is more sensitive to reverse faults than the pilot tripping zone of the remote relay. The pilot blocking zone reach is calculated by applying a margin to the remote pilot tripping zone reach and then subtracting the protected line impedance. If there are conditions that affect the apparent impedance of the line, such as a three-terminal line or a series-compensated line, then the minimum apparent impedance should be used in this calculation.

Blocking element coordination is just as important for modern POTT schemes as it is for DCB schemes [2]. The coordination process should be conducted in primary ohms in case the CTRs are different. The current supervision pickups for the tripping and blocking zones should also be coordinated if CTRs are different.

If the reach of the pilot blocking zone exceeds the NERC loadability reach, it is possible for it to continuously key carrier equipment under heavy load. Some utilities may apply load encroachment to the pilot blocking element to prevent this, but it is still required to be more sensitive than the remote tripping element. Some utilities also use the pilot blocking element for backup tripping in the reverse direction. If used in this capacity, the delay is set on par with the delay of the Step Zone 3 element.

VII. Ground Distance Protection

A combination of overcurrent and distance elements are recommended for ground fault protection. In modern relays with high-speed distance elements, the distance elements have higher speeds than the overcurrent elements. On the other hand, the overcurrent elements have better resistive fault sensitivity than distance elements.

There are a few key differences between phase and ground distance elements. Ground distance elements do not require load encroachment supervision. The margin used for ground distance is generally greater than phase distance because the zero-sequence impedance network is known with less precision. A larger margin is also used because fault resistance can cause a ground element to overreach or underreach depending on the direction of load flow [12].

All of the conditions that can alter the apparent impedance of the protected line that affect the phase distance elements also affect the ground distance elements: three-terminal lines, series-compensated lines, and lines with long lateral taps. The apparent impedances may be different for the ground elements because 3I0 will have different distribution than phase current. The apparent impedance checks should be repeated using phase-to-ground (1LG) faults for the ground elements. Unlike the phase distance elements, the apparent impedance seen by ground distance elements are also affected by mutual coupling between transmission lines.

A. Mutual Coupling

Mutual coupling can increase or decrease the apparent impedance seen by ground elements, depending on the phase and magnitude of current through the mutually coupled line [13]. Fig. 16 shows a common example of mutual coupling between parallel lines. Equation (6) demonstrates how to solve for the apparent impedance of a fault on mutually coupled parallel lines.

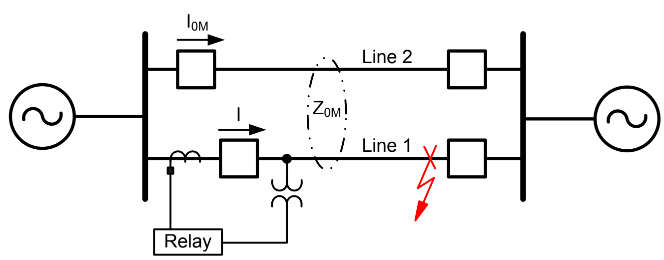

Fig. 16. Example of a ground fault on mutually coupled parallel lines.

$$
\begin{aligned}
V_a &= mZ_{1L}(I_a + k_0 I_r) + mZ_{0M} I_{0M} \\
Z_{APP} &= \frac{V_a}{I_a + k_0 I_r} = mZ_{1L} + mZ_{0M}\frac{I_{0M}}{(I_a + k_0 I_r)}
\end{aligned} \tag{6}
$$

Mutual coupling can have an impact on the effective reach of ground distance elements by altering the apparent impedance. If I_{0M} and I_0 flow in the same direction, it increases Z_{APP}, which reduces effective reach. If I_{0M} and I_0 flow in opposite directions, it decreases Z_{APP}, which increases effective reach. Another cause of reach errors is seen when mutually coupled lines are out of service and grounded at both ends, as shown in Fig. 17.

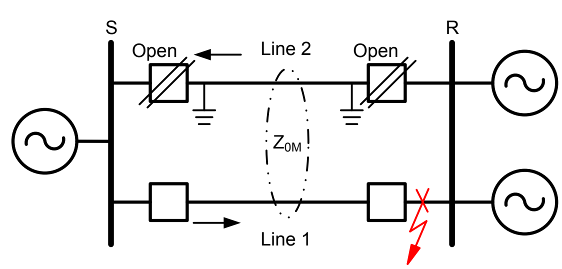

Fig. 17. Mutually coupled parallel lines with one of the lines out of service and grounded at both ends.

When a mutually coupled line is simply out of service, the apparent impedance of the in-service line is unaltered because there is no current in the mutual line. However, this is not the case when the mutual line is out of service and grounded at both ends. This forms a closed circuit, which has the effect of lowering the apparent impedance of the in-service line. This increases the effective reach of ground distance elements and may lead Zone 1 elements to overreach if their settings do not take this into account.

To properly apply ground distance reach settings, the worst-case minimum Z_{APP} and worst-case maximum Z_{APP} must be known. The relay engineer can perform checks to ensure that ground Zone 1 never overreaches and ground Zone 2 never underreaches. It is often difficult to determine when mutual coupling will cause overreach or underreach under N − 0 and N − 1. It can sometimes be difficult to find the worst-case mutual coupling effect. This is where using the brute force method might be recommended. Modern fault study programs allow engineers to automatically run ground faults at the zone boundary, with outage, one to two tiers deep. The output can be examined to find the minimum and maximum Z_{APP} for use in setting the reaches.

Because the magnitude of the mutual coupling effect is dependent on the 3I0 current magnitude in the mutually coupled line, an outage that makes that line stronger may be the worst case. For example, in a double-circuit transmission line where the mutual coupling is high, removing a ground source transformer at the remote bus for N − 1 would tend to increase the 3I0 current in both lines, which may produce the maximum Z_{APP} for setting the overreaching element.

At the very least, Z_{APP} should be checked using a 1LG remote bus fault for the following conditions:

- System normal.
- Mutually coupled line out of service.
- Mutually coupled line out of service and grounded.

Fig. 18 shows a real-world example of the apparent impedances seen for a 138 kV line that is mutually coupled with a 69 kV line. The minimum apparent impedance is 3.84 Ω, seen during system normal conditions. The maximum apparent impedance is 4.02 Ω, seen when the mutually coupled line is out of service.

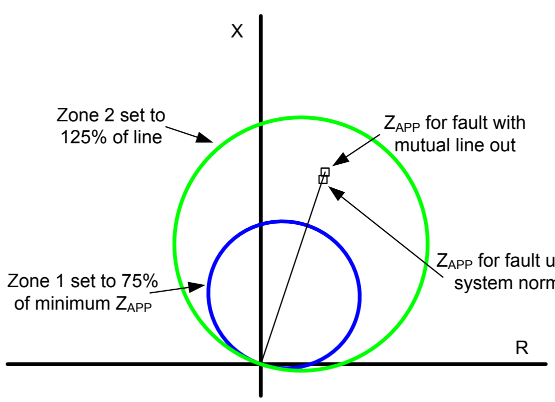

Fig. 18. Example of apparent impedances for a 138 kV line mutually coupled with a 69 kV line.

Fig. 19 shows an example of the apparent impedances seen for a line with strong mutual coupling with a parallel line. The minimum apparent impedance is 4.91 Ω, seen when the mutual line is out of service and grounded. The maximum apparent impedance is 7.53 Ω, seen during system normal conditions. Note that system normal produced the worst-case minimum in the first example, but it also produced the worst-case maximum in the second example.

The worst-case minimum apparent impedance should be used to check the underreaching elements to ensure that they always underreach. Likewise, the worst-case maximum apparent impedance should be used to check the overreaching elements to ensure that they always overreach.

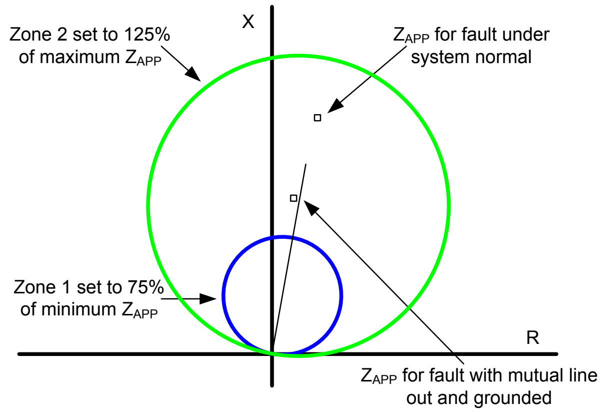

Fig. 19. Example of apparent impedances for a parallel line with strong mutual coupling.

B. Ground Step Distance Zones

Ground distance Step Zone 1 and Step Zone 2 serve similar roles to their phase distance counterparts, but with larger margins. The ground Zone 1 reach should be set to a range of 50 to 80 percent of line impedance to ensure that it never overreaches. Shorter reaches would result in slower clearing, but that is more acceptable for ground faults. Similar to phase distance Zone 1, current supervision may be required for an LOP race condition with the ground distance Zone 1 element as well. However, it only needs to be set above the maximum load unbalance (e.g., 10 percent of the winter emergency rating).

The ground Zone 2 reach can be set to a range of 125 to 150 percent of line impedance. The engineer should try to set ground Zone 2 so that it always overreaches the remote bus, but the ground time-overcurrent element can cover for instances where it does not overreach. The ground distance Zone 2 current supervision can be set to the minimum because there is no LOP race condition. A separate ground step distance Zone 2 coordination check needs to be performed even if the reach is set to the same as phase Zone 2. The flows of zero-sequence current will be different than the phase current. Any tapped branches should be checked using the same process as for the phase distance elements, but with 1LG faults instead. Mutual coupling should also be considered during both of these checks as needed.

Ground step distance Zone 3 is not required for ground distance applications because the remote backup function can be provided by the sensitive ground time-overcurrent function of the relay.

C. Ground Distance Pilot Zones

Ground distance pilot zones can be used for high-speed ground fault protection. In fact, some relays have pilot scheme logic hard-coded, so engineers must implement both phase and ground distance elements whenever a pilot scheme is enabled. The pilot scheme described in this paper uses a combination of phase distance elements for phase faults, ground distance elements for high-speed ground fault protection, and ground overcurrent elements for high-resistance ground fault protection. In a pilot scheme, the types of elements should always be matched between pilot tripping and blocking. Ground distance elements cannot be relied on to block for a ground overcurrent tripping element and vice versa.

The reach of the ground distance pilot tripping and pilot blocking zones can be set the same as the phase pilot elements in most cases. The same recommendations apply: 200 percent or more for pilot tripping, and coordination with remote pilot tripping for the pilot blocking element. For short lines, the reach may need to be greater than 200 percent of the line impedance to give the reach setting an SIR less than or equal to 5 [11]. The reaches may need to be set independently for applications that require settings to be adjusted for apparent impedances. The maximum apparent impedance should be used in the pilot tripping reach calculation. The minimum apparent impedance should be used when subtracting the line impedance from the remote tripping element reach. When coordinating with the remote relay, do not assume that the phase and ground reaches are the same. The coordination must be verified.

VIII. Ground Overcurrent Protection

Use of ground overcurrent elements is encouraged because high resistances are possible in ground fault loops. The usefulness of mho ground distance elements is limited for high-resistance faults because of the effect of infeed across the resistance. The preferred means of ground overcurrent protection are to use both a directional instantaneous overcurrent element and a directional inverse-time overcurrent element. Pilot relaying schemes also use two additional directional overcurrent elements for pilot tripping and pilot blocking. It is generally considered acceptable for the ground overcurrent elements to have a slower operating time because ground faults have less of an impact on stability and power quality. However, the higher impact of ground faults on public safety means that this comes with a cost. The public is more likely to come in contact with a line on the ground or accidentally cause a grounded object to make contact with an energized line. The use of sensitive pilot overcurrent elements is encouraged.

The following key differences make it possible to use directional ground overcurrent elements where directional phase overcurrent elements would be impractical:

- The zero-sequence line impedance is higher than the positive-sequence, so ground fault currents drop off faster with distance than phase faults do.
- The ground overcurrent elements have a less restrictive security limit based on the maximum expected load unbalance current, which can be as low as 10 percent of the winter emergency rating.
- Zero-sequence overcurrent elements will not see faults through a distribution transformer with a delta high-side winding, so this makes them more selective than phase overcurrent elements.
- Generator step-up (GSU) transformers with a grounded wye high-side winding often remain in service and act as a source of ground fault current even if their associated generation is offline. This trait can make ground overcurrent coordination easier because the magnitude of ground fault current varies less for alternate normal conditions when generation is taken offline.

These differences make ground overcurrent elements a practical choice for ground fault protection.

A. Ground Instantaneous Overcurrent

The ground instantaneous overcurrent element is an underreaching element that must not operate for faults beyond the end of the protected line. The pickup should be based on the maximum current seen for an external fault under $N - 1$ or high-probability $N - 2$ conditions. The goal is to find the condition that makes the terminal of the local relay the strongest in the zero-sequence network.

Common $N - 1$ contingencies include remote ground sources or parallel lines (or branches to a closely coupled parallel transmission path) being taken out of service. High-probability $N - 2$ conditions are considered because ground faults are the most common type of fault (see Table II). In this case, $N - 2$ is seen during automatic reclosing into a close-in fault on a remote line with its remote end open. This is in addition to a remote ground source or parallel line being taken out of service. The maximum external fault current seen during the $N - 0$, $N - 1$, or $N - 2$ conditions is used to calculate the instantaneous pickup.

A margin of 150 percent above the maximum external fault current is recommended for security. Overcurrent elements should be used with a higher margin than distance elements. Reducing the margin to lower levels is not recommended because directional ground overcurrent elements are less precise than ground distance elements. A high degree of uncertainty in zero-sequence networks also contributes to the need for higher margins. A dependability check should also be performed to see if the relay has an acceptable multiple of pickup for a close-in fault. If the multiple of pickup is not greater than 1.25 to 1.5, then there is no use in enabling the ground instantaneous element.

B. Ground Inverse-Time Overcurrent

The ground inverse-time overcurrent element is generally set to be the most sensitive but the slowest for ground fault coverage. It needs to be sensitive to high-impedance faults and to pick up for faults at the end of any tapped branches with infeed. Remote substation backup may also be required if it lacks redundancy or to cover for remote battery failures. Several ground faults, both internal and external, should be simulated to check that it meets dependability requirements. These include the minimum internal ground fault current under $N - 1$, the ground fault current seen for a remote line-end fault with infeed removed by the breaker failure function, the same fault but with infeed present to check remote substation backup, and a high-resistance ground fault. The time-overcurrent element pickup should be set to have a multiple of pickup of 2 to 3 for the minimum internal fault. A narrower margin can be used for the other fault types, and it may not even be possible to meet the requirement for remote substation backup if the infeed is strong enough. There is no definite rule for how much resistance needs to be covered, but a check should be performed to gauge how much resistance the selected pickup is capable of covering.

Automated coordination checks are recommended because of the large number of faults that must be simulated for system normal conditions and a variety of N − 1 conditions. The time-dial setting can be adjusted during the coordination process to meet the coordination time requirements. A good starting point is to base the initial time-dial setting on the intended coordination time at the maximum external ground fault current. This will not be exact, but it can serve as a good ballpark figure to start the coordination process. If the operating time is too slow (greater than 1 second) for a remote bus fault under normal conditions, then the chosen worst-case coordination point or the coordination criteria may need to be reevaluated.

C. Pilot Ground Overcurrent

The relaying engineer must set and coordinate separate directional ground overcurrent elements for use in pilot tripping and pilot blocking. The pilot blocking element should be set as low as possible, but it should also be above the maximum load unbalance current. The pilot tripping element needs to be sensitive enough to pick up for faults along the length of the protected line with a multiple of pickup of at least 2. For security, the tripping element should also have a pickup greater than the remote pilot blocking element. A margin factor of 2 is a good target. This usually results in a pilot tripping setting of 200 to 600 amperes primary.

Some applications may require these margins to be reduced for coordination purposes. The inverse-time overcurrent element can be relied on to pick up for faults that the pilot tripping element is unable to cover. The single most important requirement here is that the pilot tripping element must never be set more sensitive than the remote pilot blocking element. Coordination between the tripping and blocking elements should be conducted in primary quantities to account for CTR differences. If possible, the pilot tripping pickup should be set to the same level as the time-overcurrent pickup. It is generally not recommended to set the high-speed pilot tripping element to be more sensitive than the time-overcurrent element.

The pilot tripping pickup is often set very sensitive to cover the minimum internal ground fault current. This can be a problem on mutually coupled lines because the coupling can cause zero-sequence current above the pickup to flow in an unfaulted line. This is mainly an issue when the zero-sequence networks are isolated, with the exception of the mutual coupling. It is recommended to use only a negative-sequence directional element in most cases involving mutually coupled lines. Otherwise, it is possible for a line isolated from the fault to misoperate because the directional elements of the relay erroneously indicated a fault in the tripping region.

The reader is encouraged to study [13] for an in-depth discussion of additional considerations in setting lines with mutual coupling.

IX. Ground Directional Elements

Several issues need to be considered when setting ground directional elements for a transmission line relay. Three-terminal lines and series-compensated lines require special consideration for the settings. Very short lines or pilot overcurrent elements set very sensitive may not be able to use conventional methods for setting directional pickups. Mutual coupling can cause improperly set relays to give false directional decisions during a fault. There is much variation between directional elements between relay manufacturers. In this paper, the impedance-based directional elements that have logic to adaptively select the element making the decision are discussed [14].

A. Automatic Directional Element Settings

Modern multifunction relays calculate one directional decision that is used throughout the device. The voltage-polarized directional element sequence impedances can be calculated using (7) and (8).

$$Z_2 = \frac{\mathrm{Re}\left[V_2 (I_2 \bullet 1\angle Z1ANG)*\right]}{\left|I_2\right|^2} \tag{7}$$

$$Z_0 = \frac{\mathrm{Re}\left[3V_0 (I_G \bullet 1\angle Z0ANG)*\right]}{\left|I_G\right|^2} \tag{8}$$

The impedance-based elements measure the source impedance to the fault to make a directional decision. When the fault is behind the relay, the impedance measured is in front of the relay. Equations (7) and (8) give a positive impedance for reverse faults and a negative impedance for forward faults. The phase-to-ground fault in Fig. 20 can be used as a reference for which impedance the relay measures for forward or reverse faults. Some relays can automatically calculate the thresholds for the directional elements based on the worst-case assumption of an infinite bus at each terminal. This would reduce the source impedances Z_S and Z_R to 0 in Fig. 20. This means that the impedance measured by the relay for a reverse fault must be at least the line impedance. The boundary between forward and reverse faults is half the line impedance. The result of this method for setting the elements can be summarized as “if the fault is not in the reverse direction, it must be forward.”

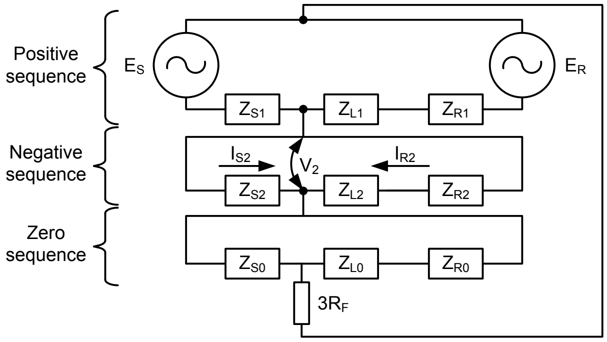

Fig. 20. Symmetrical components for a single-line-to-ground fault.

This automatic setting method works very well in most applications, such as two-terminal lines. However, it should not be used for three-terminal lines, series-compensated lines, and very short lines. Three-terminal lines need to have their directional elements set using the same approach but with three infinite buses instead (see [15] for details). The settings for series-compensated lines depend on the placement of both the series capacitor(s) and the line PTs. See [16] for instructions on how to apply the impedance-based directional elements to series-compensated lines. Non-line applications or short line applications with an impedance below 0.30 Ω secondary can use the guidance in [17] for an alternative method for setting the directional thresholds.

Automatic settings also cannot be used for applications where the pilot tripping or blocking overcurrent pickups are set below the relay default forward or reverse fault detector pickups, respectively. The directional pickups need to be adjusted down for those elements to operate correctly. If a pilot scheme with dissimilar CTRs at each terminal is used, then the directional element fault detectors need to be coordinated at each terminal, similar to the pilot tripping and blocking elements.

B. Mutual Coupling

Mutual coupling can be a cause of zero-sequence polarization problems [13]. Consider the mutually coupled line example presented in Fig. 21. Line 1 is mutually coupled with both Line 2 and Line 3, and a single-line-to-ground fault occurs on Line 2.

The zero-sequence directional elements perform properly when the electrical connection is strong between the mutually coupled sections. However, when Breaker 3 opens, as shown in Fig. 22, the zero-sequence networks become electrically isolated, as shown in Fig. 23.

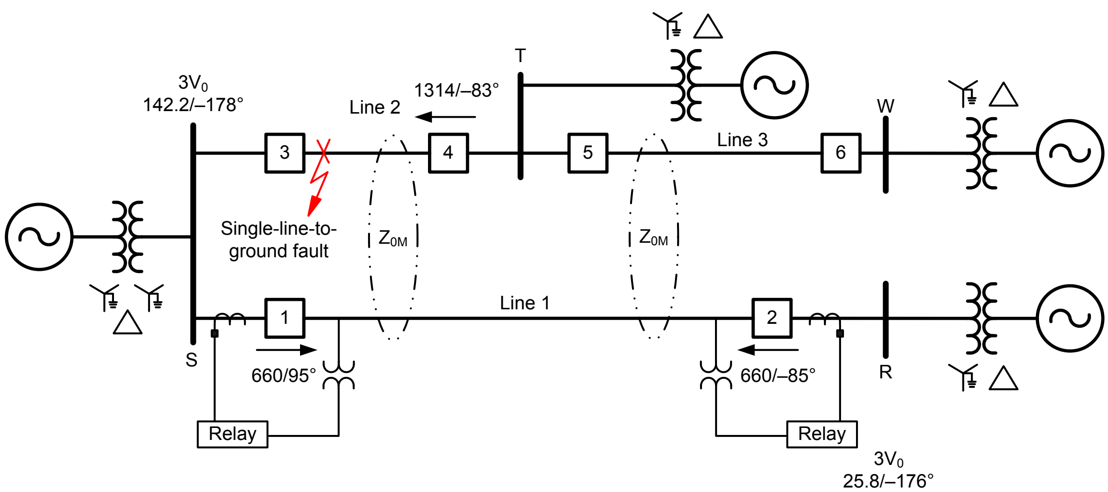

Fig. 21. Mutual coupling example with strong electrical connection.

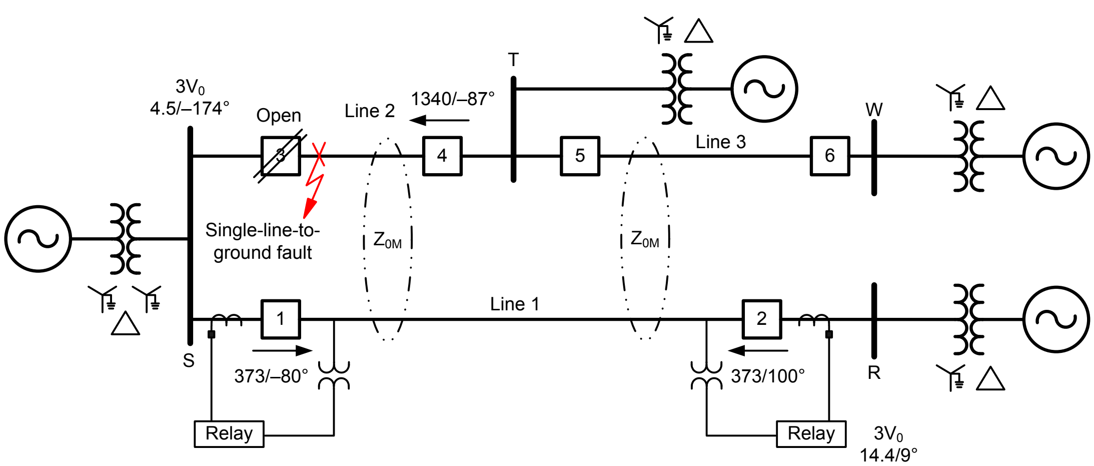

Fig. 22. Mutual coupling example without electrical connection.

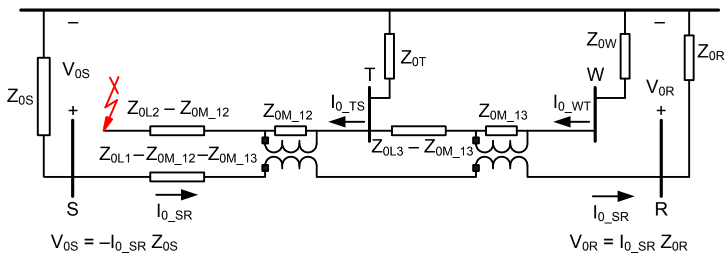

Fig. 23. Zero-sequence network of the mutual coupling example with Breaker 3 open.

The zero-sequence directional elements of the relays on Line 1 both see the fault in the forward direction even though they have already been electrically isolated. The mutual coupling caused a zero-sequence quantity reversal. This results in an incorrect directional decision for the line relay at Bus R. This makes it so Line 1 could trip for an external fault. Relays can safely avoid these issues with mutual coupling by relying only on negative-sequence directional elements instead. In relays that dynamically choose the directional element based on fault conditions, the priority order would be set to Q (negative sequence) only. This issue still exists if the relays on Line 1 have their priority order set to QV (negative sequence and then zero sequence). Once Breaker 3 opens, the negative-sequence current through Line 1 stops and the logic will switch to using zero-sequence polarization instead and make a bad directional decision.

Most relays include current-polarized directional elements as an option. However, it is not recommended to enable it when impedance-based directional elements are available in the relay. Traditionally, in the presence of a strong zero-sequence source, the line relay did not have enough 3V0 to develop torque. However, relays close to a strong zero-sequence source do have access to 3I0, which can be used for polarization instead [18]. The polarization quantity can be calculated using (9).

$$32I = \mathrm{Re}\left[I_G \bullet I_{Pol} *\right] \tag{9}$$

This is not necessary for modern relays because impedance-based elements can make a directional decision even when there is no 3V0 or 3V2 when set with the thresholds at the midpoint of the line, as described earlier. In addition, it is difficult to verify the I_{Pol} circuit because there is no observable primary current until the first ground fault occurs. It is recommended to set the priority order to QV for most applications and to Q only for mutually coupled lines. Using Q may not be an option when coordinating dissimilar relays. The setting engineer should match the directional elements as closely as possible in those cases. Also, the ground overcurrent pickup thresholds may need to be raised above the worst-case mutual current levels to avoid operating on currents resulting from mutual coupling.

X. Conclusion

Relay setting calculation templates can help engineers produce high-quality and consistent relay settings. However, these engineers need to understand the reasoning behind the templates to use them properly for a wide range of relaying applications. Experienced and inexperienced engineers alike need to know when to go beyond the cookbook.

This paper draws on the experience of the authors in setting and reviewing many transmission line setting calculations. The cases presented here represent common mistakes where the setting engineer may not identify characteristics of the line being protected that require special considerations.

Understanding the three Ss of performance (selectivity, speed, and sensitivity) and the two opposing aspects of reliability (dependability and security) and how they all interrelate is important in making decisions on choosing settings and margins for protective elements. It is important to understand that security failures are far more common than dependability failures and the relay setting engineer should strive for a good balance between dependability considerations and security considerations when setting relays.

Understanding and applying contingency analysis in determining appropriate N − 0 and N − 1 conditions for each dependability limit and each security limit for any element only comes with experience. Inexperienced engineers are encouraged to apply a brute force method of running a multitude of fault cases using the sophisticated fault study tools available today to find the worst-case conditions. This process is the best way to learn and recognize transmission system topologies that require deviating from cookbook setting criteria.

XI. References

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XII. Biographies

Michael J. Thompson received his BS, magna cum laude, from Bradley University in 1981 and an MBA from Eastern Illinois University in 1991. He has broad experience in the field of power system operations and protection. Upon graduating, he served nearly 15 years at Central Illinois Public Service (now AMEREN), where he worked in distribution and substation field engineering before taking over responsibility for system protection engineering. Prior to joining Schweitzer Engineering Laboratories, Inc. (SEL) in 2001, he was involved in the development of several numerical protective relays while working at Basler Electric. He is presently a principal engineer in SEL Engineering Services, a senior member of the IEEE, chairman of the Substation Protection Subcommittee of the IEEE PES Power System Relaying Committee, and a registered professional engineer. Michael was a contributor to the reference book *Modern Solutions for Protection, Control, and Monitoring of Electric Power Systems*, has published numerous technical papers, and has a number of patents associated with power system protection and control.

Daniel L. Heidfeld earned his BSEE and his MSEE, summa cum laude, from Michigan Technological University in 2008 and 2010, respectively. Daniel joined Schweitzer Engineering Laboratories, Inc. (SEL) in 2010 and works as a protection engineer for SEL engineering services in Fairview Heights, Illinois. He has been an IEEE member for 9 years.

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