Transmission Line Setting Calculations – Beyond the Cookbook Part II

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***Abstract*—The original paper, "Transmission Line Setting Calculations – Beyond the Cookbook," focuses on providing a practical guide to setting transmission line relays rather than on high-level theory. The guide explains the reasoning behind why certain forms of protection are applied and how to identify scenarios where an engineer must go beyond cookbook setting guidance to create good line relay settings. The guide is primarily intended to benefit engineers who are inexperienced or out-of-practice with line relay settings. However, the topic of transmission line setting calculations is broad, and many significant forms of line protection could not be discussed in detail in that paper. This sequel to the original "Beyond the Cookbook" paper continues to discuss the challenges encountered when creating line relay setting calculations and how to apply practical solutions outside of cookbook guidelines. This sequel also expands upon subjects that are only touched on in the original paper; for example, line current differential (87L) protection, three-terminal line protection, accounting for a high source impedance ratio (SIR), switch-onto-fault (SOTF) protection, and more.**

I. Introduction

The original "Transmission Line Setting Calculations – Beyond the Cookbook" paper was written to serve as a line relay settings guide for both inexperienced engineers and experienced but out-of-practice engineers [1]. It laid out the fundamentals of setting line relays, and it made the case for standardized 'cookbook' guidelines to reduce misoperations. It also illustrated several scenarios where the protection engineer would have to work outside 'cookbook' guidelines.

The original paper started by exploring the fundamentals of protection and how these apply to the practical decisions a protection engineer needs to make. It explains that, in general, protection engineers have two "knobs" to adjust when creating settings for a protective element in a relay: sensitivity and delay. Further, it explains the need to check the settings under contingencies that challenge them. Importantly, it notes that not all alternate cases are N-1 contingencies. If something is taken offline often enough, then it would simply be an alternative normal N-0 configuration.

The paper introduced frequently used relaying schemes and how they influence protection security and dependability. Note that well-designed and set schemes can improve both dependability and security, improving reliability. The paper also covered the basics of setting phase distance, ground distance, and ground overcurrent protection. It focused on discussing the underlying principles that govern our use of these elements. The intent was to help the protection engineer understand what compromises they can make when creating settings for difficult-to-protect transmission lines.

The original paper covered several notable topics outside the scope of most line settings cookbooks:

- Limits to applying a load encroachment function.
- Protecting long taps off two-terminal lines.
- Coordinating short lines next to long lines.
- Adjusting ground distance for mutual coupling.
- Adjusting directional settings to avoid misoperations due to mutual coupling.

However, several significant forms of line protection and challenging scenarios were not discussed in detail to keep the length of the paper reasonable. This sequel is meant to serve as a supplement to the original paper to cover the following topics in more detail:

- Line current differential schemes
- Three-terminal line protection
- Setting lines with high source impedance ratios (SIRs)
- Switch-onto-fault (SOTF) overcurrent protection
- Loss-of-potential (LOP) overcurrent protection
- Setting lines near inverter-based resources (IBRs)

II. Line Current Differential (87L)

There are many approaches to protecting the whole length of a transmission line using schemes such as step distance, directional comparison blocking (DCB), permissive overreaching transfer trip (POTT), and line current differential (87L). Naturally, step distance schemes rely on timing and reach coordination whereas pilot schemes such as DCB and POTT are communication-based to provide selectivity for overreaching phase and ground elements. Remote end relays can send either a block signal or permissive signal depending on their scheme. Many times in protection engineering we must prioritize security or dependability, but good schemes can improve both simultaneously; 87L is a good example of this. Line current differential schemes provide high-speed simultaneous clearing of all internal faults. 87L applications are becoming more widely used due to their inherit characteristics of being unaltered by weak terminals, series compensation, power swings, and unconventional short-circuit current sources [2].

A. 87L Basics

Generally, 87L schemes are considered highly selective, which means they do not have to be coordinated with relays on adjacent zones of protection. However, in line applications with tapped loads, this is no longer the case unless 87L relays can be added at all load terminals. We talk about the challenges presented by tapped loads in more detail within Section II.C of this paper. The current differential elements include per phase (87LP), zero sequence (87LG), and negative sequence (87LQ). Note that not all 87L relays include 87LG or 87LQ elements. Of these elements, the negative-sequence element has the highest probability of being disabled. This is discussed further in Section II.B.

Setting calculations can be achieved in one of two ways: determine a setting and ensure it meets dependability and security limits, or establish the limits first and then choose a setting that fits in between [1]. For most settings, the authors favor finding the limits first, then choosing a setting that fits between the two limits. When determining an appropriate 87L element pickup value in per unit (pu), the protection engineer should keep in mind the possibility of mismatched current transformer ratio (CTR) at each terminal.

The calculated dependability limit should cover for all internal faults under contingency and with a margin of 2.0 to 3.0 times pickup. A line-end fault with remote terminal open under an N-1 source contingency generally provides the minimum internal fault current. If only the 87LP elements are enabled, the fault type used for this check is whichever gives the minimum phase current. If 87LG is enabled, ground faults are expected to be covered by that element. If 87LQ is enabled, unbalanced faults can be covered by that element. This means if both 87LQ and 87LG are enabled, 87LP only needs to be checked using 3LG faults. If only 87LP and 87LG are enabled, 87LP can be checked using line-to-line faults.

To calculate a security limit with the 87LP, it is desirable to set the pickup greater than load with a small margin of 110 to 120 percent. This will avoid tripping the line if someone isolates the local relay and opens a current transformer (CT) test switch under normal load while forgetting to isolate the relays at both terminals. Of course, if using sensitively set unbalance elements (87LQ or 87LG), be sure to enable loss-of-current blocking logic in the relay to prevent tripping because the three test switch poles are not opened perfectly simultaneously. The line-charging current also imposes a security limit. If charging current compensation is not in use, the 87LP pickup must be set greater than the charging current by a factor of 2 to 3 to account for inrush.

The simple rule here is to calculate the dependability limit (must be less than minimum internal fault with margin) and the security limit (greater than load) and take the smaller of the two limits. That is, favor dependability if the dependability limit is lower or favor sensitivity if the load security limit is lower.

B. Setting 87LG and 87LQ

87LG and 87LQ differential elements can be more sensitive than the 87LP element. This is because they are not restrained by balanced load flow through the zone of protection. In transmission applications, there is very little unbalance current in the load flow, so the operating signals used by the 87LQ and 87LG elements come strictly from the fault. These elements are used to supplement the phase element. 87LG will provide sensitivity to ground faults and the 87LQ can cover all unbalanced faults. High sensitivity for faults involving ground is important because they can have significantly higher fault impedance compared to phase faults.

If the engineer wants to set 87LG or 87LQ more sensitive than the 87LP element, a value of 0.10–0.20 pu is a good starting point. The lower the pickup is set, the more coverage it will provide for worst-case internal high-impedance faults, as this is the overall intent. If the pickup is set to these low levels, it should easily be less than the desired dependability limit with a margin of 2.0 to 3.0 times pickup for internal faults. For this reason, some cookbook guidelines omit dependability checks for 87LG and 87LQ entirely.

As for the security check, 10 percent of winter emergency rating is used for the 87LG and 87LQ imbalance differential elements. This check can also be considered unnecessary if the CT is tapped such that the winter emergency rating does not exceed the nominal rating of the CT. This is because 0.1 pu is commonly seen as a minimum setting for the 87L function in relays. In addition, 87LG and 87LQ elements are designed with extra security features so sensitive settings can be used.

IBRs like wind and solar facilities are becoming more prevalent in today's power grid. These tend to be weak sources, so we want to use protection elements with high sensitivity; use of 87LQ and 87LG is recommended. However, IBRs are often programmed to suppress negative-sequence current injection during an unbalanced fault. See Section VII for more discussion on protecting lines connecting IBRs to the bulk electric system (BES). For this reason, 87LQ may not provide as much sensitivity as expected. Generally, IBR facilities are connected to the BES using transformers that allow a significant flow of zero-sequence current, so 87LG helps.

C. Tap Load Transmission Line

Contrary to popular belief or other possible 87L cookbooks or guides, current differential line protection can be applied even when load taps exist on the line that do not have 87L relays to create a zone boundary at the tap point. Note that this requires all distribution transformers tapped off the line to be modeled. Not all system models are maintained with these transformers included because tapped load transformers typically do not contribute fault current.

1) Using Security Checks to Account for Load Taps

First, the protection engineer should check if the 87LP pickup can be set greater than all through current on the low side of the tapped transformer(s). This includes load, external faults (low side of tapped transformers), and inrush of the tapped transformers. If the pickup can be set to 1.25 to 1.5 times the maximum through current and still meet dependability limits, no additional changes need to be made to that element. Because the 87LQ element can see through delta high-side windings, it can be checked using the same method as 87LP but with negative-sequence currents. The protection engineer may choose to simply disable the 87LQ element due to its reduced sensitivity limiting the dependability and because of security concerns on transformer inrush. 87LG elements do not see through delta high-side windings, so no adjustment needs to be made for load taps that provide isolation in the zero-sequence network between the high-side voltage and low-side voltage. If the 87L pickup settings cannot be set greater than low-side through current (for security) while covering the protected transmission line (for dependability), an alternative approach must be considered.

2) Applying Local Supervision of 87L

Protective elements responding only to local signals can be used to determine if the fault is on the protected line and not beyond a tap. The logic in the relay must be set in a way that the supervising elements give permission to trip before the 87L elements can operate. Using local elements to supervise 87L protection is a compromise. We often use differential protection because of its superior sensitivity and selectivity relative to other types of protective elements. The element operates on knowing the total current into the zone of protection so it can be very sensitive—even if one or both terminals are very weak. Using protective elements that operate on local quantities only to supervise the 87L elements eliminates this inherent advantage. However, the advantage of being very selective to respond to currents only flowing into its zone boundaries makes 87L protection useful for lines with tapped loads. The 87L elements will not overreach into adjacent transmission system zones. Often, the local permissive elements can be set very sensitively to allow tripping for line faults, yet not sensitive enough to see external faults limited by the impedance of the tapped transformers. The local AND combination of 87L with local supervising elements (21 and/or 50 elements) can provide a good compromise for security from both external transmission system faults (87L) and events on the taps (local supervising elements).

It should also be noted that some 87L relays apply a disturbance detector (87DD) function that supervises the 87L element. Depending on the relay type, the 87DD function may operate only on local terminal contribution or may take both terminals into account. The 87DD function is generally intended to protect against communication errors and it may not have adjustable settings, so it is not suitable for use in the tap load supervision role.

Instead of being set greater than all low-side through current as required by the 87L-only method, the 87LP pickup setting only needs to be greater than the maximum tap load current with local supervising elements. Even if the 87L element picks up for a low-side fault, the supervision will not permit it to operate. Note that in the case of multiple tap transformers, the sum of each transformer's maximum load current is used to set 87LP. The same margin of 1.25 to 1.5 times can be used to prevent it from picking up on load.

Inherently, if the tap transformer provides zero-sequence network isolation, the 87LG cannot see through it. Thus, there is no need to check it against the tap load or low-side faults. In contrast, the 87LQ element can see through a delta high-side transformer. This provides justification for disabling the 87LQ element when there are tap transformers on the line. The 87LG element will provide the coverage for the high-resistive ground faults without the possibly of having the 87LQ element see through the delta high-side tap transformer(s).

The distance and overcurrent elements applied as supervising elements must be set so they cover the full length of the transmission line without picking up for through current on the low side of the trapped transformer(s). These checks are performed with the remote terminal(s) open to maximize the local terminal current contribution. If the relay has existing backup distance elements, they may be re-used as our 87L distance supervision. Step Zone 2 or Step Zone 3 should already cover the end of the transmission line, and the protection engineer just needs to check those settings against the transformer low-side through currents. As with most distance elements, a margin of 125 percent should suffice.

87L overcurrent supervision can be applied to supplement the distance supervision discussed previously. This is done to cover for LOP conditions, and because ground overcurrent supervision provides better fault resistance coverage for ground faults than ground distance supervision. The phase overcurrent supervision must be set greater than the transformer through currents. This supervision can also be set greater than the winter emergency rating of the line for additional security, but doing so is not required due to its role as a supervisory element. The setting should be checked to see if it covers the transmission line, but doing so can be difficult for lines with high conductor ratings relative to fault current. In contrast, most ground overcurrent supervision is only set greater than 10 percent of the winter emergency current rating. The ground current supervision will not be able to pick up for faults on the low side of tap transformers with zero-sequence isolation. Frequently, the pickup resulting from this criterion can cover the transmission line without issue.

These supervisory element guidelines assume that there is a single blocking setting in the relay that applies to all 87L elements. If any of the 87L supervisory elements is asserted, 87L trips will be permitted. It should also be noted that the local supervision solution can cause the 87L line relay to misoperate due to simultaneous events. A fault on the low side of the transformer could be high enough for the sensitive 87L setting to pick up. If the supervising elements pick up for a fault or other event beyond the remote terminal at the same time, it results in a false trip at one terminal. Such simultaneous events are rare and not typically a serious security risk.

3) Supervising Elements and Week Infeed

Additional consideration must be given if 87L supervising elements are applied, but the line also has a weak terminal, i.e., a radial line, wind farm, or solar farm. Normally a weak terminal will not impact an 87L scheme, but the addition of local supervision changes that dynamic. If a terminal is weak enough, it may not be possible to set an 87L supervisory element sensitive enough to pick up for all internal faults. If the supervising elements never pick up, the 87L trips are always blocked. Disabling the supervision will simply re-introduce the problem it was intended to solve, and the 87L element would no longer be blinded to faults on the low side of the tapped transformer. There are a few different solutions that can be applied to accommodate the weak terminal: 87L direct transfer trip (DTT) functionality, asymmetric 87L settings, and weak infeed permissive logic.

It is not uncommon for modern 87L relays to include an 87L DTT function as a part of their line current differential element.

If this function is used, the strong terminal can send an 87L DTT signal to the weak terminal whenever it would normally trip. This will allow the weak terminal to trip at the same time, but there are still issues to be considered. Some relay models have 87L block logic that will also block their 87L DTT function. If the supervising elements for tap load are implemented using that relay's default 87L block logic, the weak terminal's supervising elements would block the 87L DTT signal. If an independent DTT channel is not available, one of the following alternatives can be considered.

The asymmetric solution requires the 87L pickups at the weak terminal to be set differently from the strong terminal. Normally, relay setting cookbooks recommend that the 87L pickups are set to identical values in primary amps, but some relays support them being set independently. The weak terminal will have its 87L pickups set using the method laid out in Section II.C.1. This will limit the sensitivity of the 87L relays at that terminal, but it requires no logic changes aside from not applying local supervising elements at the weak terminal.

For the weak infeed permissive solution, the 87L relay can use the communication channel from the 87L scheme to assert a data bit whenever a remote supervising element picks up. The designated weak terminal needs to have logic programmed to treat this fiber channel bit as one of its supervising elements. The result is that the weak terminal can trip for internal faults even if it has no local source of fault current. The strong terminal will not need to have this logic in place.

4) Multiple Load Taps and Inrush

When working on a transmission line tapped with one or more load transformers, the engineer must account for the inrush current observed during energization to avoid false tripping. Traditionally, the inrush current is estimated as a multiple of transformer nameplate rating. This estimate is independent of system conditions, and it may be unrealistic for lines with weaker sources. The authors use a simple alternative where a 3LG fault on the low-side winding is used in place of the inrush current. To run this check in a way that simulates inrush, one of the line terminals needs to be open and the worst-case maximum value is used. Remember, however, that an 87L scheme configured for tapped load protection as discussed in Section II.C.1 should not pick up for low-side faults, even if both terminals are closed.

If setting tapped load protection for a line with multiple transformers tapped off of it, the protection engineer may try to calculate inrush by applying a multiple to the sum of each transformer nameplate rating. However, this could result in an unrealistically high current that the system cannot support. As an alternative, the authors apply simultaneous 3LG faults to the low-side bus of each tapped transformer in the line differential zone. As before, this simulated inrush event is run with one of the line terminals open. This simultaneous fault method is quite conservative, but it may improve on the estimate based on the sum of transformer ratings.

III. Three-Terminal Line Protection

Depending on the system configuration, three-terminal line protection can present significant challenges to protection engineers. The protection engineer must have a firm awareness of the security and dependability limits so they know when performance compromises may need to be made.

A. Infeed and Outfeed

Unlike a normal two-terminal line with a source at each end, three-terminal line protection must take apparent impedance into account for internal faults. Both system configuration and fault location can impact the apparent impedance to the fault. The protection engineer must take this apparent impedance behavior into account to properly set the line relays.

The apparent impedance to the fault measured by the protective relay (Z_{APP}) can be calculated with (1).

$$Z_{APP} = Z_L + \frac{I'}{I} Z'_L \tag{1}$$

Infeed is when I' is greater than I as shown in Fig. 1, so Z_{APP} for the end of zone fault is greater than $Z_L + Z'_L$. Outfeed is when I' is less than I as shown in Fig. 2, so Z_{APP} for the end of zone fault is less than $Z_L + Z'_L$. If the breaker nearest the fault in Fig. 2 trips before the other terminals, the same system will change from outfeed to infeed. Such complications must be considered when creating settings for three-terminal lines.

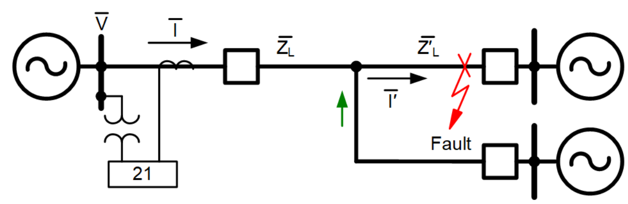

Fig. 1. Three-terminal infeed example

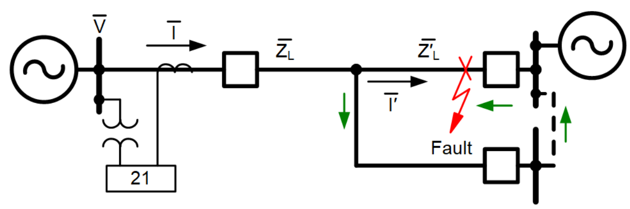

Fig. 2. Three-terminal outfeed example

B. Setting Guidelines

If a relay settings cookbook mentions three-terminal line settings, it is usually focused on recommendations for distance settings. The short-reaching Zone 1 element must be set so it underreaches both remote terminals with margin. Most cookbooks recommend setting it to a percentage of impedance to the closest remote terminal without infeed. This recommendation is suitable for most three-terminal lines because they are affected by infeed, which increases Z_{APP} for remote bus faults when all terminals are closed. However, this recommendation assumes there is no outfeed reducing the Z_{APP} to the fault location. To avoid this issue, a catch-all recommendation is to base the Zone 1 reach on the minimum apparent impedance calculated for faults at each remote bus under normal and N-1 source conditions.

For most applications, the medium-reaching Zone 2 and long-reaching Zone 3 elements are set so they overreach both remote line ends with margin. Most cookbook recommendations address the need to simulate the maximum Z_{APP} for faults at each remote line end with the remote terminal open or closed. The cookbook-recommended reach is a percentage of maximum Z_{APP}. This recommended dependability limit can be improved by accounting for N-1 conditions, which can increase the maximum Z_{APP}. In extreme N-1 source cases, it can be difficult to cover the maximum Z_{APP} with both overreaching zones while preserving coordination. In those instances, Zone 2 can be set with all sources in service where loss of communication will be the N-1 contingency applied.

The pilot reverse zone also needs to have its calculations adjusted for three-terminal lines, but not all cookbooks account for that fact. The typical calculation for the pilot reverse zone will subtract the protected line impedance when checking coordination with the remote relay's pilot forward zone. For three-terminal lines, this calculation must be run once for each remote relay's pilot forward zone. The calculation must subtract the minimum Z_{APP} between that remote terminal and the local terminal. Each pair of terminals uses a different minimum Z_{APP} for this check.

The winter emergency rating of the transmission line will limit the distance reach settings as they do for two-terminal lines. However, three-terminal lines may have a different rating for each terminal. The rating is based on the most limiting series element between the local terminal and the three-terminal tap point.

For three-terminal lines, the impedance-based fault locator can give accurate results as far as the tap point. Past the tap point, however, infeed or outfeed will interfere with the accuracy of the calculation. Unlike distance protection, the apparent impedance cannot be applied to avoid this accuracy issue. There are a variety of ways to set this function, and there is no one correct answer. Some relays use the line angle setting for protection, which can impact the protection engineer's choice:

- Use impedance data from the local terminal to the tap point. This choice is good for applications that use automatically calculated directional settings based on the line impedance. This may not be an option if the impedance to the tap point is too low.
- Use impedance data between the local terminal and farthest remote terminal. This choice will give subsequent engineers a better idea of total line length by looking at the settings file.
- Use impedance data from the local bus to whichever remote bus gives the desired line angle. This choice only applies to relays that use the line angle setting for protection.

Normally, the impedance per unit length and the line angles are similar for each branch of a three-terminal line. Therefore, most lines will not see a major impact from this setting decision. Also, some line current differential and traveling wave relays with communication can exchange information to give an accurate fault location on multiterminal lines.

Pilot directional overcurrent elements also need additional checks applied when protecting three-terminal lines. The original paper recommends a target margin of at least 2 between forward and remote directional elements at each terminal. This is still true for three-terminal lines. However, in outfeed scenarios the current can be split between two blocking terminals for an external fault [3]. To cover for this, the forward overcurrent pickup must be set greater than the sum of both remote terminals' reverse elements with margin. Some cookbooks cover for this by simply requiring a margin of at least 3, and they assume the blocking elements are set the same in primary amps. A general recommended margin is 1.25 to 1.5 times the sum of both remote blocking pickups.

C. Communication-Assisted Schemes on Three-Terminal Lines

As with two-terminal protection, communication-assisted protection allows faults to be cleared at high speed for the full length of the transmission line. There are some differences in their functioning to account for the additional terminal.

An 87L is the simplest element to apply to three-terminal lines because the pickup settings are the same as with two-terminal lines. The main changes are related to communication settings and ensuring the information for both remote terminals is present.

A DCB scheme is impacted the least in the change from two to three terminals. If any terminal sees a fault in the reverse direction, it sends a blocking signal for both remote relays. It supports sequential tripping easily when compared to permissive transfer trip schemes. Sectionalizing the line by opening a disconnect switch in the middle of the line will not lead to reliability failures as with some other schemes. There are few drawbacks to applying a DCB scheme over other pilot tripping schemes to three-terminal lines. However, applications where outfeed is a possibility can result in delayed clearing until one of the terminals opens to allow current to redistribute.

A POTT scheme on a three-terminal line requires a key signal from **both** remote terminals to permit communication-assisted trips [3]. It is necessary to get a signal from both remote terminals to preserve security because a fault directly behind one terminal is expected to be visible to the other two terminals. Modern POTT schemes (hybrid POTT schemes) add reverse blocking elements to prevent echoing permissive for an external fault. Echo functionality is also affected because the permissive condition must be satisfied before the echo timer starts. That means two of three terminals must see the fault before the third terminal can echo. An echo cannot be triggered if only one terminal sees the fault. The echo-convert-to-trip function can be used to trip weak terminals if both strong terminals see the fault.

A permissive underreaching transfer trip (PUTT) scheme on a three-terminal line requires a key signal from **either** remote terminal to permit communication-assisted trips. Because Zone 1 is the permissive zone, it is not necessary to get a signal from both remote terminals to ensure the fault is in the zone of protection. However, a PUTT scheme will not provide full coverage of the line if the Zone 1 reaches do not overlap [3]. Fig. 3 depicts a three-terminal line where the Zone 1 reaches set at each terminal may not overlap due to the close proximity of two of the terminals. For example, if the relay at L uses a reach of 0.8 pu and the relay at R uses a reach of 0.16 pu, there is a gap between them where the PUTT scheme will not operate.

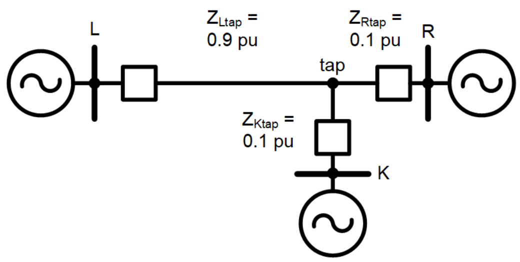

Fig. 3. Example three-terminal line where Zone 1 reaches may not overlap

A direct underreaching transfer trip (DUTT) scheme allows high-speed tripping of the whole line if the fault lies inside the Zone 1 reach of any terminal. However, when applied to a three-terminal line, a DUTT scheme will not provide full coverage of the line if the Zone 1 reaches do not overlap [3].

D. Three-Terminal Breaker Failure Coverage

As laid out in the original paper, phase distance Step Zone 3 can be used to cover for a breaker failure scenario. For a two-terminal line, it will be set to cover the protected line and the adjacent circuit element connected by the failed breaker. The reach is set to cover the sum of both circuit impedances without infeed. Infeed is not considered in the calculation due to the assumption that the remote station applies a local breaker failure function. However, for three-terminal lines, the infeed is not eliminated from the remote terminals. The calculation must be performed with Z_{APP} for a three-phase fault at the end of the adjacent line instead. The fault simulation must be done with the failed breaker and the adjacent circuit isolated as they would be by the breaker failure function.

Depending on the system configuration, the breaker failure Z_{APP} for three-terminal lines can exceed NERC maximum distance reach. As discussed in the original paper, even the load encroachment function has limits when extending beyond the NERC maximum reach [1]. If such lines cannot employ a breaker failure DTT function, the relays may need to rely on sequential tripping to clear the fault.

For ground faults, ground overcurrent elements will generally have an easier time covering for breaker failure scenarios due to their sensitivity. If ground overcurrent elements are not applied, the ground distance elements need to be set similar to phase distance but using the worst-case maximum Z_{APP} for a ground fault instead. Either approach may still need to rely on sequential tripping if the local terminal fault contribution is too weak.

E. Sequential Tripping on Three-Terminal Lines

Sometimes one terminal on the three-terminal line is weaker because another terminal provides a shorter path to the fault. This will result in lower fault currents and higher measured Z_{APP} for that terminal until the shorter path trips open. For some applications, this increased Z_{APP} can be severe enough to exceed the relays' maximum reach settings. The measured fault currents could fall less than the minimum pickup thresholds of the relays as well. Sequential tripping is a strategy where the weaker terminal is set so it trips after the shorter path trips open for the fault. The weaker terminal's protection is set to cover the farthest remote bus of the three-terminal line without infeed from the shorter path. Sequential tripping can be used with both communication-assisted primary protection and time-coordinated backup protection. However, some types of communication-assisted protection are challenged by sequential tripping.

Engineers setting 87L schemes generally do not need to be concerned about sequential tripping. Each 87L relay operates on the differential current (it has information on the current entering the zone from all terminals) rather than only the local fault contribution. However, the protection engineer should remember that local 87L disturbance detector functions and tapped load supervising elements are subject to local terminal contributions (see Section II). Similarly, for DCB schemes, no changes need to be made to support sequential tripping because the weaker terminal can still block for reverse faults. Once the shorter path trips open, the weaker terminal will have full visibility of the line, and the relay can often trip at high speed.

POTT schemes have difficulty with sequential tripping scenarios because the relays may rely on echo to trip at high speed for some faults on the line. For the weaker terminal to echo, it needs to see a key signal from both remote terminals. If one of the strong terminals opens first, the key signal may have dropped out from the now-open terminal, causing a repeat of the echo process to allow the breaker at the weak terminal to open using the pilot logic. If both stronger terminals trip and open before the weaker terminal can, the weaker terminal relays must clear the fault with time-delayed backup elements.

Another complication can occur if only one of the strong terminals opens on a Zone 1 trip before the echo is sent. The open terminal's key signal may drop out unless it also incorporates open breaker keying. If both line relays on the remaining closed terminals can pick up the fault, the open terminal starts its echo timer instead of the formerly weaker terminal. However, it is possible that only one remaining line relay can pick up for the fault. The terminal that relies on sequential tripping still might not be able to pick up the fault in its pilot forward zone, so both remaining terminals need to clear the fault using backup time-delayed elements. This race condition can be avoided by reducing the echo timer, as adding a delay to Zone 1 is undesirable. This timing adjustment may not be an option in all applications. An alternative scheme can help avoid these issues.

POTT and DUTT schemes can be combined to improve the dependability of the line protection. This solution avoids the possibility of an echo race and time-delayed backup clearing of the weaker terminal. To provide full line coverage, faults outside the Zone 1 reaches must be covered by the POTT scheme and settings may need to be adjusted accordingly.

POTT and PUTT schemes can be combined to improve dependability on three-terminal lines, but this does not resolve all the problems we have outlined. The scheme would have separate key bits for POTT and PUTT. The permit setting is modified to assert when it receives the PUTT key from either remote terminal or POTT key from both remote terminals. This hybrid scheme does not need to wait for echo for faults inside the Zone 1 reach of another terminal.

F. *Weak Terminals on Three-Terminal Lines*

It is possible for one of the three terminals to be significantly weaker than the other two. This weakness can have a variety of causes:

- There is variable or intermittent power generation behind the terminal.
- It is a load terminal with a blocking relay applied for added selectivity.
- It is weak only because another terminal on the three-terminal line provides a shorter path to the fault (see Section III.E).

Blocking relays can be added to load terminals to account for large distribution transformers where pilot tripping zones can pick up for low-side faults. This enhances selectivity and allows the other terminals to improve their sensitivity to line faults. The reverse element pickups and reaches can be set using existing guidelines. Without a source, there is no need to set the forward protective elements. However, some systems may have a small amount of back-feed from their distribution transformers, so additional protection needs to be applied to clear line faults. Hybrid POTT echo-convert-to-trip function is a secure choice, but it requires voltage elements to be set.

The voltage pickup set points should be checked for sensitivity against the worst-case internal faults. When applying voltage protection, phase-to-phase undervoltage elements can be relied on for phase faults. Neutral overvoltage elements can be used for ground faults if the transformer winding behind the relay is ungrounded or is a delta winding. Grounded wye transformer windings can serve as a source of ground fault current, so they should be used in place of neutral overvoltage protection. Unconditional voltage protection should be used with caution to avoid security failures. A low-set overcurrent fault detector is strongly recommended, and sequential tripping may be necessary to avoid miscoordination with neighboring lines. These are not concerning for the hybrid POTT echo-convert-to-trip function because the strong terminals effectively serve as supervising elements.

G. *Protecting Three-Terminal Lines With Open Disconnect Switches*

An operator may wish to keep a normally three-terminal line in service with one of the branches segmented to isolate it from the other two as depicted in Fig. 4. The line sections between Bus L and Bus K are operated as a networked line, and the line section connected to Bus R is operated as a radial line. This can be done for maintenance reasons, and it may be more common on subtransmission lines with tapped load transformers.

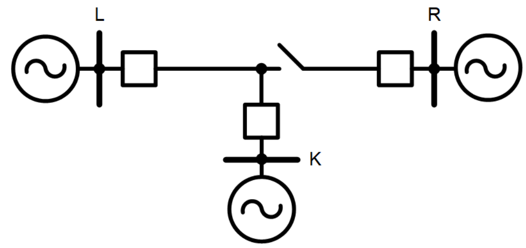

Fig. 4. A three-terminal line where one branch is segmented

The line relays at each terminal should already have backup elements coordinated with one or both remote terminals open, so it is likely they can be applied without modification. However, the high-speed communication-based protection should be examined in greater detail.

87L can be applied to a segmented three-terminal line if the relays support a stub bus function. A stub bus function zeroes out the current signals sent or received to the remote terminal(s). This function allows the networked line section and the radial line section to each retain their high-speed protection. If the line has load transformers tapped off of it, the tapped load logic may need to be checked.

How a DCB scheme accounts for the three-terminal line in Fig. 4 depends on the type of communication channel used. No modification may be necessary if power line carrier communication is used because the radial line section is disconnected from the networked line section. Otherwise, a cutoff function will be necessary to prevent blocking signals from being sent or received by the radial line section line relay. The relays on the networked line section can still send blocking signals to each other so they can operate as normal. The pilot trip zones and pilot block zones should already be coordinated with each other even when one of the breaker terminals is not contributing fault current.

A POTT scheme would encounter some issues if implemented as is. For a fault in the networked line section, the relay on the radial terminal must echo before a communication-based trip can happen. For a fault in the radial section, the relays in the networked section will not see enough permissive signals to echo. Remember that the three-terminal POTT scheme needs to see permissive signals from both remote relays before it can start the echo timer.

A PUTT scheme may also encounter difficulties if implemented as is. If the Zone 1 elements of the networked line relays cannot cover the entire networked section, the networked section loses high-speed protection for that portion of the line. The PUTT scheme will not contribute for faults on the radial line section. The relays in the networked section can echo the PUTT permissive signal, but the radial line relay is already tripping on Step Zone 1 regardless.

A DUTT scheme has similar Zone 1 coverage issues to the PUTT scheme. Any portion left unprotected by any Zone 1 element cannot trip at high speed. If the DUTT scheme is implemented normally, a fault in the Zone 1 reach of any relay will also cause the isolated line section to trip unnecessarily.

The scheme could benefit from a cutoff function implemented in the radial line relay that blocks the DTT signal from being sent or received.

IV. SIR Guidelines

The original paper described the importance of calculating the SIR when setting transmission line relays [1]. The SIR is mainly used to determine if a transmission line is electrically short and is used when setting underreaching distance elements. The authors do not believe that SIR is very useful for setting underreaching (high-set, instantaneous) overcurrent elements.

It is recommended to check the SIR under conditions with all sources in service (N-0), and with a source contingency that makes the terminal weak (N-1). Checking both conditions allows the protection engineer to obtain a better understanding of the topology of the system being protected. The original paper gave a brief description of how to determine the source impedance to use in calculating the SIR and referred the reader to [4] for more details.

The advice given in the original paper on what to do when the line is determined to be electrically short under N-0 or N-1 conditions was terse. It can be summarized as follows:

- 4 < SIR < 10: Rely on high SIR functions available in the relays to remain secure.
- 10 < SIR < 30: Additionally, reduce the Zone 1 reach to obtain more margin.
- SIR > 30: Turn off the underreaching Zone 1 element.

Of course, the limits listed are general guidelines and should be adjusted based on manufacturer recommendations for the relay being applied. The question that begged to be answered was how much should the reach be reduced when the SIR falls between 10 and 30?

Previous guidelines on application of underreaching distance relays relative to SIR focused on capacitively coupled voltage transformer (CCVT) transient errors only, and the authors felt that they did not adequately address other sources of error [5]. More recently, [6] provides a thorough discussion of the possible sources of error that should be considered when selecting underreaching margins. This section discusses SIR in much more depth than the original paper.

A. How Much Should I Pull the Reach Back?

Since writing the original paper, the authors have started applying an equation to give a recommended maximum reach based on SIR. It uses an assumed steady-state voltage measurement error at very low voltages. The derivation of the equation follows. We start with the equation for SIR for phase faults (2):

$$\mathrm{SIR} = \frac{Z1_{\mathrm{SOURCE}}}{Z1_{\mathrm{LINE}}} \quad (2)$$

Multiply the numerator and denominator by the current in the line, I_{RELAY}, to obtain (3). $V_{\mathrm{NOM}} - V_{\mathrm{RELAY}}$ determines the voltage drop across the source impedance for determining $Z1_{\mathrm{SOURCE}}$:

$$\mathrm{SIR} = \frac{V_{\mathrm{NOM}} - V_{\mathrm{RELAY}}}{V_{\mathrm{RELAY}}} \quad (3)$$

where:

V_{NOM} is 1 pu voltage behind the source.

V_{RELAY} is the voltage at the relay for a remote out of zone fault.

Rearrange the equation to solve for V_{RELAY} in terms of SIR and V_{NOM} to obtain (4).

$$V_{\mathrm{RELAY}} = \frac{1}{\mathrm{SIR}+1} \bullet V_{\mathrm{NOM}} \quad (4)$$

Equation (4) gives the voltage at the relay for an out-of-zone fault at the remote bus. The maximum allowable reach with accommodation for error will be the ratio of the measured voltage (assuming a negative error term) to the true voltage for an out of zone fault as shown in (5).

$$\mathrm{Reach}_{\mathrm{MAX}} = \frac{V_{\mathrm{RELAY}} - V_{\mathrm{ERROR}}}{V_{\mathrm{RELAY}}} \quad (5)$$

We can estimate V_{ERROR} in secondary volts for use in (5). Because it is often easier to think of accuracy in percent or per unit as opposed to absolute values, we can convert V_{ERROR} from secondary volts to pu using (6).

$$\mathrm{ERROR}_{\mathrm{PU}} = \frac{V_{\mathrm{ERROR}}}{V_{\mathrm{NOM}}} \quad (6)$$

If we multiply both sides of (6) by V_{NOM}, we can substitute that version of (6) along with (4) into (5). The V_{NOM} terms cancel in the numerator and denominator. We can then rearrange the equation in terms of SIR and $\mathrm{ERROR}_{\mathrm{PU}}$ to get (7).

$$\mathrm{Reach}_{\mathrm{MAX}} = 1 - \mathrm{ERROR}_{\mathrm{PU}}\left(\mathrm{SIR}+1\right) \quad (7)$$

For example, estimate that the relay measurement error at very low voltage is ±0.5 V. Assume an additional 1 percent error to accommodate other sources of error. For a 66.4 V_{LN} nominal voltage transformer secondary circuit, $V_{\mathrm{ERROR}} = 0.5 + 0.01 \bullet 66.4 = 1.16\ \mathrm{V}$. Using (6), we get $\mathrm{ERROR}_{\mathrm{PU}} = 0.0175$ (1.75%).

If we plot (7) for a range of SIRs from 1 to 40 using the assumption of 1.75 percent error, we get Fig. 5. The guideline starts pulling reach back from the typical rule-of-thumb reach margin of 80 percent when SIR > 10. This seems reasonable and useful to the authors. If a more conservative security margin is desired, the error term can be multiplied by a margin factor or greater errors can be assumed. For example, using a margin factor of 1.5 times the assumed error of 1.75 percent gives $\mathrm{ERROR}_{\mathrm{PU}} = 1.5 \bullet 1.75\% = 2.625\%$ for use in (7). With that modification, (7) gives a maximum reach recommendation of 71 percent at SIR = 10.

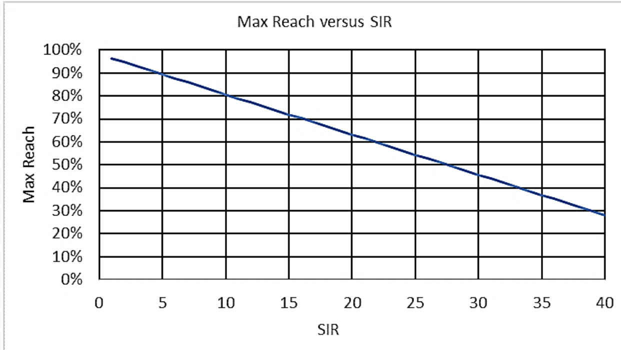

Fig. 5. Maximum reach versus SIR assuming 1.75% steady-state error

Fig. 5 plots the maximum reach as high as SIR = 40. The guidelines in the original paper said to turn off Zone 1 when SIR > 30. Examining Fig. 5 shows that we could still get Zone 1 coverage of 28 percent of the line at SIR = 40. Here, the physical length of the line can be used to consider if the benefit of Zone 1 outweighs the security risk of Zone 1. If the SIR is high because the line is physically short, 28 percent may provide coverage of only a short length of the line. If the SIR is high because the system is weak, 28 percent may give coverage for a useful length of the line.

It is important to note that we still need to accommodate other sources of error besides measurement errors in our underreach margin factor, and these must be given due consideration in evaluating the result of (7) in determining our overall reach setting [6].

B. Possible Shortcomings of SIR

SIR is not a perfect measurement. In the interest of a balanced discussion, this section examines the measure further. Many discussions on networked transmission line protection use simplifications such as reducing the network to a simple two-source network with a single transfer impedance. That single branch is used as the transmission line for purposes of illustrating various protection concepts, or treating the system as a radial system, which is certainly valid for studying networked transmission lines when the remote terminal is open. For the purposes of understanding fault studies, neglecting the transfer branch does a disservice to engineers learning protection.

(1) Source Impedance Varies Depending on Location of the Fault

The SIR as defined in [4] and [7] is only valid for one point in the power system—a fault at the remote boundary of the line zone. The strength of the source behind the relay is not a constant and varies with the location of the fault along the line. As explained in [4], the transfer branch plays a significant role in determining the source impedance.

Fig. 6 illustrates the concept. In Fig. 6. (a) and (b), we have reduced the system to a simple two-machine equivalent with the line of interest and the transfer branch to represent the rest of the interconnected power system in parallel with the line under study. This is similar to Fig. 3 of [4], except we have split the line impedance to allow sliding the fault along the line by varying m. Factor m is the per unit distance of the fault from RELAY L. Note that Fig. 7 of this paper is also a reproduction of Fig. 3 of [4].

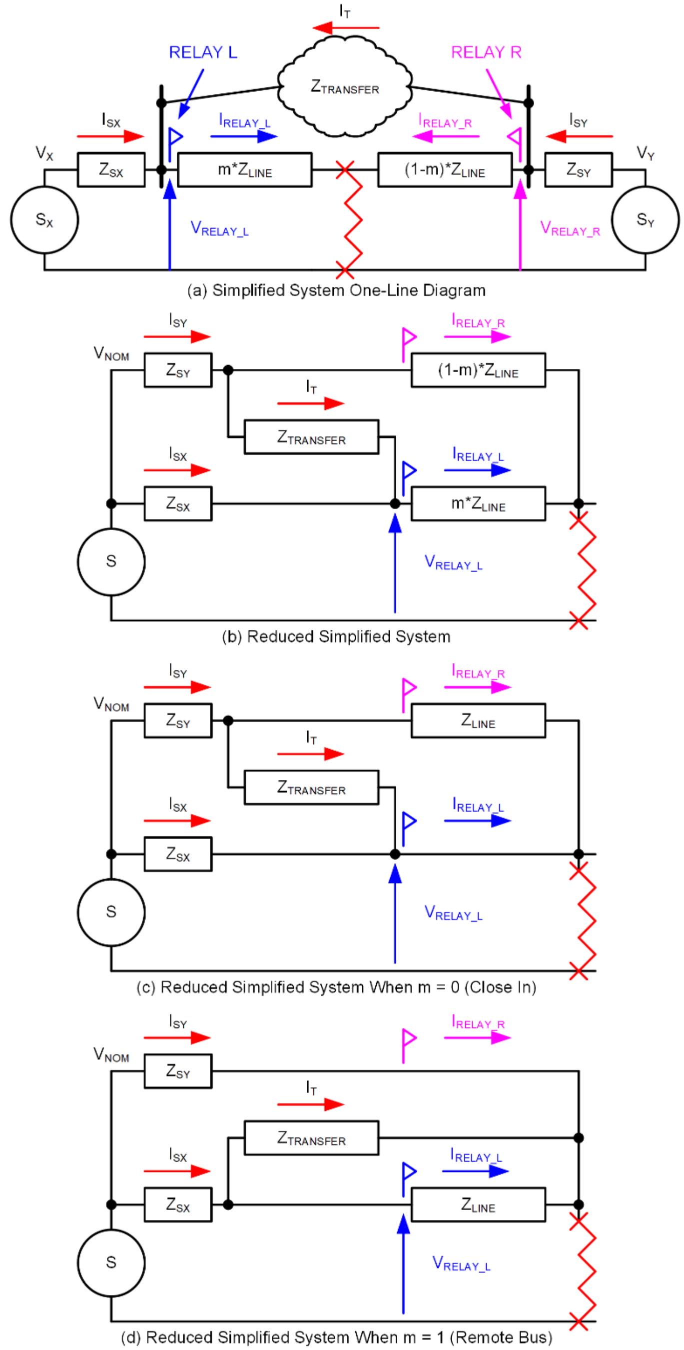

Fig. 6. Strength of source behind relay relative to fault location

For the extreme case of a close-in fault at the left terminal (m = 0) shown in Fig. 6. (c), the fault contribution from the remote equivalent source, I_{SY}, divides between the line, I_{RELAY_R}, and the transfer branch, I_T, and adds to the current observed by the relay. This makes the source impedance for a close-in fault the parallel impedance of Z_{SX} and $(Z_{SY} + Z_{TRANSFER})$. Depending on the significance of $(Z_{SY} + Z_{TRANSFER})$ relative to Z_{SX}, the source impedance for a close-in fault can be much lower than for a fault at the remote bus.

This variation of source impedance depending on the location of the fault is not terribly relevant to what we are using SIR for. Remember, we use SIR to help us set underreaching elements such that they never trip for an out-of-zone fault. For this reason, the relevant source impedance used to determine SIR uses the boundary condition of m = 1 as shown in Fig. 6. (d). We can see that the transfer branch is in parallel with the line branch increasing the current through Z_{SX} and, therefore, reducing V_{RELAY_L}.

To help understand the difference between Fig. 6. (c) and (d), it is important to note that the direction of fault current flow in the $Z_{TRANSFER}$ branch is opposite at these two extremes of m. At some point, depending on the relative magnitudes of the impedance of the two sources and the transfer branch, there will be a value of m where the current in the transfer branch becomes zero.

(2) V_{RELAY} Does Not Vary Linearly With m

Examining the typical voltage profile diagram used to explain the concept of SIR, one might think that the voltage at the relay varies linearly as the fault slides along the line. Fig. 7 is a reproduction of Fig. 3 from [4]. We expect that the voltage will always be higher and the current lower the farther the fault is from the relay and, therefore, a fault at the remote bus will be the worst case.

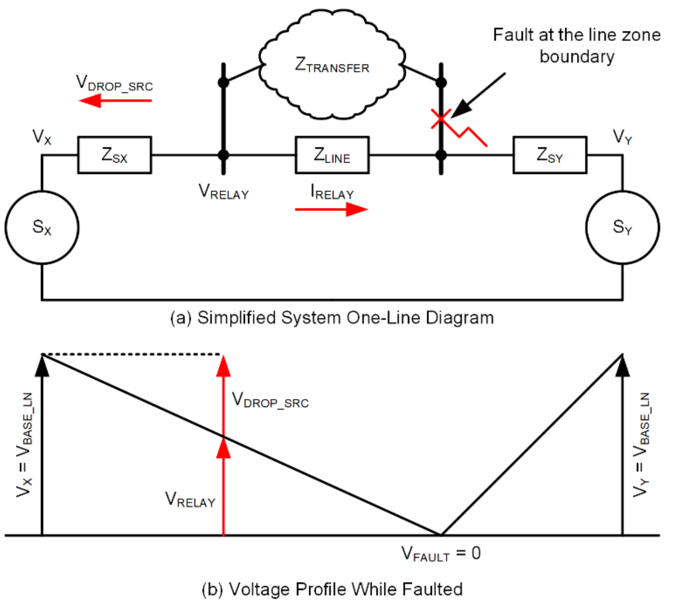

Fig. 7. Voltage profile while faulted at the remote zone boundary

This is not what happens. As described in Section IV.B.1, the source impedance changes depending on the location of the fault on the line. Reference [4] uses two examples to illustrate why we calculate the source impedance using a fault at the remote line zone boundary. We use those same examples here to show example voltage profiles.

Example 1 from [4] is a short line in a closely coupled system. Fig. 8 plots the voltage and current profile in pu for Terminal W (the left terminal) along the line. The SIR in Example 1 is 4, making it a borderline short line according to [7]. More importantly, the transfer impedance branch is low—similar in magnitude to the line branch impedance. We can see that V_{RELAY} for a fault at 100 percent of the line is actually lower than at 70 percent of the line. At first glance, this is not the expected behavior.

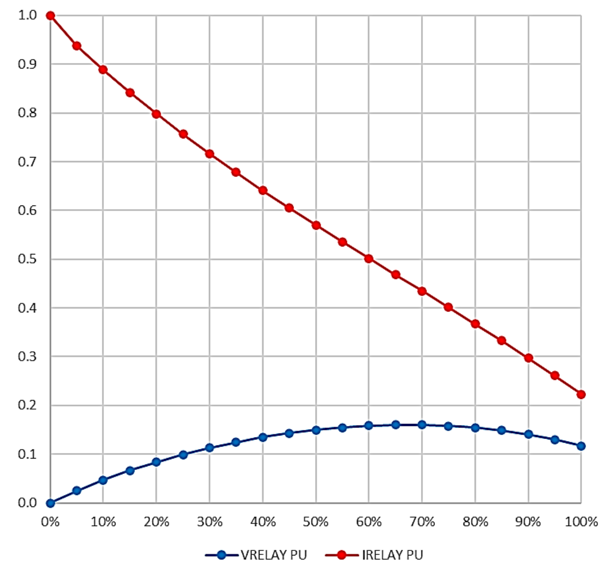

Fig. 8. V_{RELAY} with m varied from 0 percent to 100 percent, closely coupled system

Now consider Example 2 from [4], a tie line between two utilities. Fig. 9 plots the voltage and current profile in pu for Terminal N (again the left terminal), in pu along the line. The SIR in Example 2 is 0.54, which makes it a borderline long line according to [7]. More importantly, the transfer branch impedance is very high between the two systems—over 13 times the magnitude of the line branch impedance. In this case we can see that the voltage profile as m varies is not a straight line, but this example follows the expected contour where I_{RELAY} gets lower and V_{RELAY} gets higher the farther the fault is from the relay.

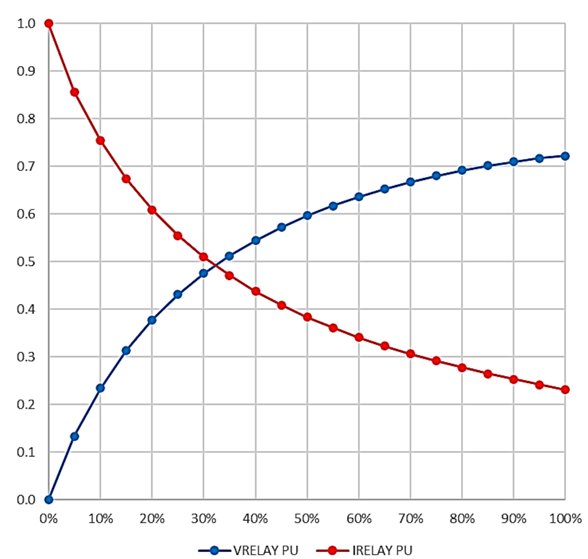

Fig. 9. V_{RELAY} with m varied from 0% to 100%, tie line

Examining the difference between Fig. 8 and Fig. 9 should cause little concern on the usefulness of SIR as a guide for determining the maximum safe reach. Because (7) is based on an accommodation for V_{RELAY} error for a fault at the line zone boundary (m = 1), and the SIR is based on V_{RELAY} at the line zone boundary as well, the fact that the voltage profile could be arched in some applications instead of sloped upwardly is a good thing. The relay has a larger V_{RELAY} signal to work with for faults near the reach setting boundary, so any error will have less impact.

(3) Final Thoughts on the Usefulness of SIR

It is important to understand that "reach" is the main "knob" we have to adjust. When we set the reach to 60 percent of the line, it does not mean that we will be upset if the relay trips for a fault at 60.1 percent of the line. In fact, it is perfectly acceptable if the relay *sometimes* trips for an in-zone fault at 99.9 percent of the line—just so long as it *never* trips for an out-of-zone fault at 100.1 percent of the line.

It is possible that more rigorous (and possibly more complex) analysis methods could be developed to give more precise guidance on selecting underreaching distance element security margins. On the other hand, SIR is very simple to calculate, (8) and (9), and use (7), to inform protection engineers about how much margin to use. The authors believe that a simple method that can be used on every line and yields acceptable results is more useful than a complex method that may not be used. Several shortcomings of SIR were considered and were concluded to be of little consequence.

C. *Simplification of SIR Calculation*

Reference [4], which was also used in the original paper, was written as a tutorial and illustrated the ratio using impedances. If you multiply the top and bottom impedances by the relay current as we did in (3), you get back to voltages, which is what we are actually trying to do. The equations simplify to (8) and (9), which are equations (30a) and (30b) from [6]. The simplified equations have the advantage of only having to enter the relay voltage from the fault study into the calculations instead of entering both relay voltage and current for the remote bus fault.

$$SIR_G = \frac{1}{V_{PU(LG)}} - 1 \quad (8)$$

$$SIR_P = \frac{1}{V_{PU(LL)}} - 1 \quad (9)$$

D. *What About a Line With High SIR Under N-1?*

As mentioned in the introduction to Section IV, when doing SIR evaluations we always recommend checking SIR under both system normal and worst-case single contingency conditions. Often, a line terminal at a tap station will have an extremely high SIR when the transmission line behind it is removed from service and the remaining source is unconventional generation or a networked subtransmission system. We always want to set our relays considering any possible N-1 condition [1].

For example, consider a line with an SIR < 10 under N-0 and an SIR > 30 under N-1. In such an application, we have a conflict. To maintain security under N-1, we would likely turn off the underreaching distance elements. However, for system normal, which will be the case the vast majority of the time, we will have no trip unconditional high-speed protection. This may be considered a poor compromise in the tradeoff of speed and dependability versus security.

In this example, the high SIR is caused by the weak N-1 source and not by the line being short. Often, there will be a significant difference between the fault current calculated for a line fault under N-0 conditions versus under N-1 conditions. In these cases, we can calculate and set the underreaching distance element's supervisory fault detectors with a dependability margin less than the calculated N-0 fault current and a security margin greater than the calculated N-1 fault current. Dependability is obtained under system-normal conditions and security is obtained under single-contingency conditions. This compromise balances security and dependability better. If there is not enough difference between the dependability limit and the security limit for the fault detectors, this approach is not a suitable solution for the application.

V. SOTF Schemes

SOTF schemes consist of logic that detects when a breaker is open or when a breaker is being commanded to close and allows certain protective elements to trip for a short window of opportunity after the breaker is closed. Typically, these elements are not set to be fully selective so they cannot be enabled at all times.

SOTF schemes are used to cover two scenarios. The classic application of SOTF is to protect for a zero-voltage fault when the source of polarizing voltage for the distance elements is on the line side of the breaker. In this case, the distance elements may not operate due to lack of polarizing voltage. The classic scenario for a zero-voltage fault on the transmission line is when closing into a set of three-phase grounds that were inadvertently left on the line.

The SOTF scheme is also used to provide instantaneous protection for faults on the entire length of the line when energizing it. It is not possible to overreach an open breaker; often, the overreaching elements are allowed to trip through the SOTF scheme without time delay. For this reason, SOTF schemes should be applied regardless of whether the voltage transformers are on the line side or bus side of the breaker.

Many SOTF schemes have logic to close the SOTF trip window of opportunity when voltage is detected on the line side of the breaker, which indicates that the remote breaker has already closed and the SOTF scheme is not necessary. This voltage reset logic should be enabled to enhance scheme security. The goal for SOTF logic is to clear the fault as quickly as possible to minimize equipment damage [8].

In applications with bus-side potential, the scheme may trip the breaker when energizing a faulted bus using the line breaker. This is useful for buses that do not have bus differential protection, or as backup for buses without dual differential protection.

A. SOTF Setting Guidelines

We recommend setting one of two types of schemes in the SOTF scheme to cover these two requirements: an instantaneous phase overcurrent element (50P) supervised with an undervoltage element (27P) with overreaching Zone 2 elements (no time delay), or a non-directional distance element (a distance element with reverse offset that includes the origin in the tripping characteristic) if available. Set properly, either of these schemes deliver dependability for zero-voltage faults as well as clearing faults with no intentional time delay anywhere on the line [8].

B. SOTF Via 50P AND 27P With Overreaching Zone 2 Elements

Fig. 10 shows common SOTF logic. The logical AND of 50P and 27P protection is used to cover the zero-voltage fault while the overreaching Zone 2 elements (with no delay) are used to cover the line. Typically, the 50P element was set based on a close-in fault under N-1 and the 27P element was set to 0.2 to 0.3 pu voltage because any voltage greater than that would allow the overreaching phase distance elements to operate dependably with acceptable speed. The performance of the ground distance elements during SOTF conditions is not significantly impacted because there are two healthy phases to quickly charge the positive-sequence memory. However, with this approach there was no attempt to analyze the overlap of coverage of these two protective elements. Reference [8] provides more rigorous guidance on how to set the 50P and 27P elements to ensure fast and dependable three-phase fault coverage of 100 percent of the line, including the zero-voltage fault, during the SOTF window of opportunity.

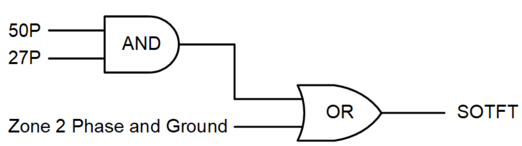

Fig. 10. SOTF trip logic [8]

Adding voltage supervision (27P) to the 50P SOTF element is strongly recommended. It does not block the 50P element from operating when the distance elements do not have polarizing voltage. It can also be used to prevent operation of the 50P element when the remote terminal is closed during the SOTF window. Using 27P supervision is even more secure than the voltage reset option mentioned because there is an inherent delay in the voltage reset function closing the window of opportunity to trip to ensure fast operation during a simultaneous reclose into a faulted line.

When undervoltage supervision is used, the 50P element can be set without checking security from load pickup. The line is not part of the BES and subject to loadability checks until both terminals of the line are closed. The voltage supervision can be set at or lower than 0.7 pu to meet NERC requirements. Likewise, including 27P can provide additional security against tap transformer inrush. Voltage supervision can also be applied to the overreaching distance elements as well if they can assert on inrush.

The dependability check for 50P is accomplished with a 3LG line-end fault (with end open) under N-1 source contingency. A dependability margin of 1.5 to 2.0 is recommended.

Reference [8] recommends setting the 27P element based on (10). SIR_{WEAK} is the SIR determined for the fault case used to calculate the 50P setting.

$$27P_{PU} = \frac{1}{\left(SIR_{WEAK} + 1\right)} \tag{10}$$

If voltage supervision is not applied, the 50P pickup must be at least 150 percent of load as a minimum for the security check, as the element should not operate per NERC PRC-023.

C. SOTF Via a Non-Directional (Offset) Distance Element

Another method for implementing SOTF is with non-directional phase and ground distance elements. A distance element with reverse offset includes the origin in the tripping characteristic. This type of element does not use memory voltage and can trip with no delay for a zero-voltage fault. The forward reach can be set to overreach the line. For this reason, adding the overreaching elements to the SOTF scheme is not necessary to cover 100 percent of the line. The use of the nondirectional element allows the engineer to precisely define the zone of operation during energization and is naturally dependable for close-in faults [8].

The offset mho element depicted in Fig. 11 involves two settings: a forward reach and a reverse reach. The recommended settings are:

$Z_{FORWARD}$* is 120 percent line impedance (ZL)

$Z_{REVERSE}$ is about 20 percent line impedance (ZL)

*If Zone 2 is used, a fraction of the line impedance can be used to cover close-end faults.

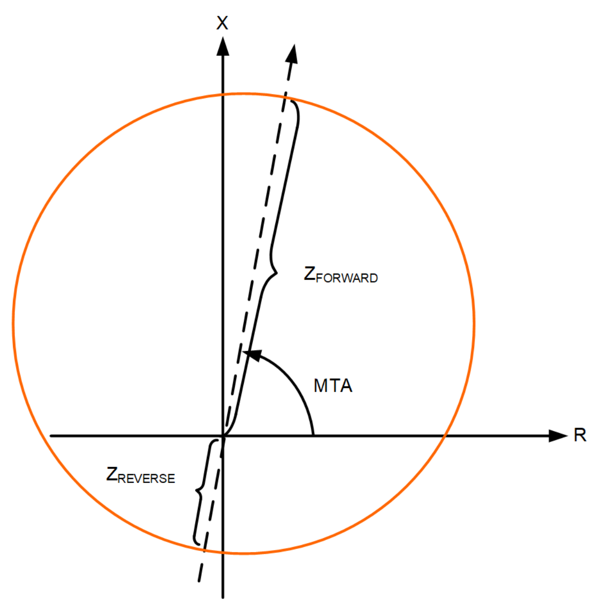

Fig. 11. Nondirectional mho distance element [8]

VI. LOP Overcurrent Protection

When modern microprocessor relays determine there has been a failure in their voltage source, they will declare an LOP condition. This condition will typically disable impedance-based protection, and it may modify the behavior of current-based protection according to the settings. Typically, the user is allowed to set the relay with a security bias (all directional overcurrent elements become disabled) or with a dependability bias (all forward directional overcurrent elements become non-directional) upon detection of an LOP condition. The original paper does not recommend using overcurrent protection for phase faults due to their insecurity as the system changes over time [1]. Thus, the system can end up with no protection for phase faults during an LOP condition if the LOP condition effects both redundant protection systems.

A dependability-oriented solution involves enabling a non-directional overcurrent element with a short time delay under LOP conditions. For dependability, this element must be sensitive enough to cover the minimum internal fault current for the protected line. This check is commonly an end-of-line fault run with the remote terminal open due to the assumption that the remote terminal will operate first. This fault does not need to be run under an N-1 source contingency because the LOP condition would make that an N-2 check. Also, the fault type used for this check is determined by what other current elements will be in operation under LOP conditions. If the ground time-overcurrent element is set to be non-directional under LOP, the phase LOP overcurrent element will not need to cover ground faults. In this case, a line-to-line fault is used. As for margin, the typical 1.5 to 2.0 multiple common to instantaneous overcurrent elements should be sufficient. For security, try to set the element greater than the winter emergency rating of the transmission line with margin if possible.

The overcurrent element must also have a sufficient time delay to avoid miscoordinating with neighboring protection. A definite time-overcurrent element can be time-coordinated with the neighboring high-speed protection. Step Zone 2 is set to 20+ cycles to coordinate with Step Zone 1 plus breaker failure. However, this LOP overcurrent element is an N-1 scheme, so the delay only needs to be set to 8–12 cycles as shown in Table I of [1]. It is just enough to coordinate with a normally cleared instantaneous element on an adjacent zone.

However, if the end-of line fault currents are low enough, a pickup may not be able to satisfy both the security and dependability criteria. The protection engineer can choose to prioritize one criterion over the other. Remember that the winter emergency rating is a worst-case load based on conductor size and probably has little to do with realistic line loading even under high load-flow conditions. Having an LOP N-1 condition coincide with loading at the winter emergency level would be very rare. Therefore, this scheme could feasibly be set from 67 percent to 80 percent of winter emergency as a compromise between security and dependability.

The use of this LOP overcurrent scheme also depends on the application. A line protected by an 87L scheme is not dependent on voltage to protect against internal faults. The LOP overcurrent scheme may not be used at all, or the logic can be set so it requires both the loss of communication and an LOP condition before it is enabled. Or, if the protection engineer assesses that there is little chance of both redundant protection schemes experiencing a common LOP condition, this scheme may not be warranted.

VII. Lines Near IBRs

Since the original paper was written, there have been significant changes in the power system that affect how we set transmission line relays. Unconventional resources associated with renewable energy are gaining an ever more significant share of the resource mix supplying the BES and can be dominant in some parts of the grid during certain hours of the day. These unconventional resources, including photovoltaic (PV) solar, Type 3 and Type 4 wind turbine generators (WTGs), and battery energy storage systems (BESS), are asynchronously connected to the grid and are either completely or partially interfaced with the BES through power electronics, hence referred to as IBRs [9].

The short-circuit behavior of IBRs can be quite different from conventional generators. They behave as current sources as opposed to a voltage behind an impedance and have comparatively low short-circuit contribution—typically in the range of 1.2 to 1.3 times rating. The control systems often suppress injection of unbalanced currents during short circuits, which challenges protection systems that rely on negative-sequence quantities. The negative-sequence quantities they do produce may not have coherent angular relationships compared to conventional resources. Further, they have no natural inertia, which can result in rapid changes in frequency during a disturbance that challenges memory polarized protection elements. This is just a very brief summary of protection challenges presented by IBRs. Much has been written on these challenges in recent years. The authors suggest [9]–[12] for further study.

Solutions to these challenges are still maturing. Additionally, industry standards such as IEEE P2800 *Standard for Interconnection and Interoperability of Inverter-Based Resources Interconnecting with Associated Transmission Electric Power Systems* are being developed to specify performance requirements for IBRs connected to the BES under abnormal conditions. For now, the authors urge a healthy caution when using protection elements that rely on negative-sequence quantities in applications where the line may be supplied only by IBRs. Negative-sequence quantities are commonly used in several elements:

- Distance element fault-type identification and selection (FIDS) logic.
- Directional elements that supervise protective elements that respond to unbalanced phase faults (phase-to-phase and phase-to-phase-to-ground faults).
- Directional elements that supervise protective elements that respond to faults involving ground (phase-to-ground and phase-to-phase-to-ground faults).

The typical applications to be concerned about are lines that connect IBR facilities to the BES and lines at stations where taking one line out of service results in the IBR facility being the only remaining source behind the relay. Fig. 12 illustrates a typical application. Line LR has been split into Lines LP and RP by installation of a point-of-connection substation for an IBR facility. Relay R_{IP} always has nothing but IBR sources behind it. Relays R_{PL} and R_{PR} normally have grid sources behind them but have only the IBR source during the N-1 condition where the other grid connection line is out of service. The other relays on these lines are not shown.

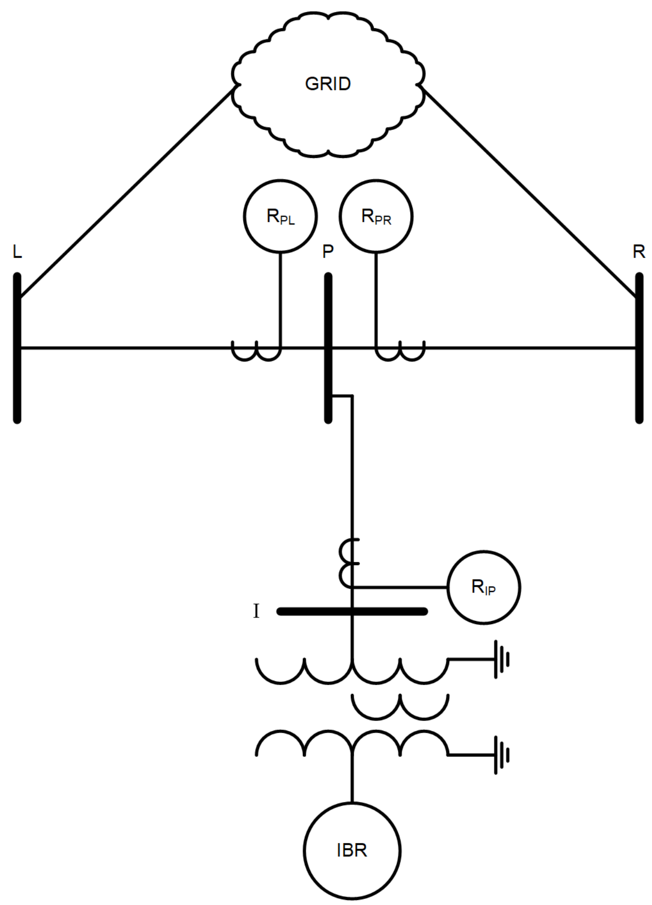

Fig. 12. Typical IBR connection to the BES

A. *Ground Fault Protection of Lines Sourced by IBRs*

One observation that is commonly made is that Bus I has a strong path for zero-sequence current, even though the positive- and negative-sequence networks may not due to the current-limiting nature of the IBRs and the fact that the intermittent resources (solar or wind) may not be available so the IBRs are offline. Industry guidance for many years has recommended giving negative-sequence voltage polarized directional elements (32Q) priority over zero-sequence voltage polarized directional elements [13]. IBRs often suppress negative-sequence current injection, and the negative-sequence quantities that they do inject often, at least for the first several cycles, do not have a coherent phase relationship [10]. For this reason, we recommend giving the zero-sequence polarized directional element (32V) priority for ground relaying in the applications illustrated by Fig. 12.

In IBR line applications with significant mutual coupling where 32Q supervision is preferred, the protection engineer can use the 3I2 fault detector setting guidelines described in the next section to help mitigate impact of the IBR sources on security.

B. *All Protection of Lines Sourced by IBRs*

Although setting ground directional priority to 32V addresses concerns with negative sequence for protection elements supervised by the ground directional element, it does not address the fact that negative-sequence quantities are used for FIDS logic that supervises distance elements during unbalanced faults and for other phase elements supervised by the negative-sequence directional element. Protection security can be further improved if we can address negative sequence for these functions as well.

Many relays use the phase angle relationship of I2 and I0 for FIDS logic. When I2 is not available, the I2/I0-based FIDS cannot enable the correct ground distance elements. Some relays supplement the current-based FIDS scheme with an undervoltage-based FIDS scheme when I2 is not available [14]. If the I2 fault detector does not assert, the voltage-based FIDS is used to enable the correct ground distance elements. For relays that do not have undervoltage-based FIDS, insufficient 3I2 prevents the ground distance elements from operating. Use of ground directional overcurrent elements in these relays is recommended to supplement the ground distance elements.

One strategy to enhance security of relays protecting lines sourced by IBRs is to raise the negative-sequence fault detector thresholds greater than the level expected from poorly behaving IBRs [11]. Doing so can prevent the protective elements from making decisions on weak and incoherent negative-sequence quantities and having security failures. Of course, this strategy requires using other elements to cover the reduction in dependability that may be introduced by de-sensitizing the vulnerable elements. These solutions may include use of 87L, voltage-based weak feed tripping logic in pilot schemes, and/or time-delayed undervoltage tripping schemes. Of course, we have always needed to rely on weak source schemes to cover the case where the intermittent resources are not available, e.g., nighttime for a PV IBR, or are running at reduced capacity, e.g., operating curtailed during transmission congestion.

For example, relay R_{IP} always has only IBR sources behind it. This line would best be protected by 87L protection making the dependability of distance and directional overcurrent elements less important. Relays R_{PL} and R_{PR} are only vulnerable to security issues when under N-1 contingency. These relays might use the setting guidelines in [11] and summarized here to selectively control elements vulnerable to security failures due to poor negative-sequence current injection.

The maximum phase fault current from the IBR source is estimated using (11):

$$IMAX_{PH} = 1.3 \cdot \frac{MVA_{IBR}}{\sqrt{3} \cdot V_{LL}} \quad (11)$$

Neglecting load, we know that for a phase-to-phase fault, 3I1 and 3I2 will be 1.732 times the phase current. We want a dependability margin for the 3I2 fault detectors that is less than $1.732 \bullet \text{IMAX}_{\text{PH}}$. According to [11], the poorly performing IBRs modeled in the study tended to suppress 3I2 to less than $0.5\ \text{IMAX}_{\text{PH}}$. We want a security margin greater than that. Reference [11] recommends setting the 3I2 forward fault detectors to around 1.25 times IMAX_{PH}, such that the negative-sequence-dependent elements in the relay will only operate when the source behind the relay is either Type 3 WTGs or there is a grid source behind the relay. The study showed that the Type 3 WTGs, doubly fed asynchronous generators (DFAGs), provided coherent negative-sequence quantities while the full converter IBRs did not. It should be noted that the study was limited, so any conclusions drawn should be considered with that in mind.

It is important to note that this guideline for setting the 3I2 fault detectors applies to both the forward and reverse elements in the relays at both terminals of the line. The fault detectors in the reverse elements must always be coordinated with the forward elements in the remote relays in a pilot scheme. The remote relays on these lines are grid sourced for forward faults, so one might be tempted to set their forward fault detectors lower than this guideline to enhance sensitivity and dependability to separate the IBR-sourced lines from the grid. But, these relays are IBR sourced for reverse faults, so their performance when blocking is equally important. Further, generally the lowest set fault detector between forward and reverse is the setting used to control the FIDS logic. For this reason, the reverse 3I2 fault detector should not be set too low in the relays at both ends of the line. Reference [11] recommends setting the reverse 3I2 fault detectors to 1.00 times IMAX_{PH} to still be greater than the expected output of the poorly performing IBRs and be coordinated with the forward fault detectors set at 1.25 times IMAX_{PH}. To summarize, the guideline applies to the relays at both ends of the line that can be sourced only by IBRs under either N-0 or N-1 conditions.

Reference [15] gives additional details on recommended modifications to logic to enhance security for the relays shown in Fig. 12. These include supervising forward phase-distance elements, dynamic time-delay schemes for underreaching and overreaching distance elements, and use of time-delayed undervoltage backup tripping elements.

C. Future Developments

As stated in the introduction to this section, protection practices relating to IBR sources are still maturing. When the performance requirements of BES-connected IBRs are standardized and these new IBRs start comprising a significant portion of the installed base, the guidelines presented here may need to be refined. Because the performance of IBRs under abnormal conditions comes from control algorithms and not from the laws of physics, there will likely always be a period of uncontrolled response lasting as long as 2.5 cycles until the control algorithms can control the current injection. If future IBRs provide increased 3I2 injection but the angle is still transiently incoherent, using the magnitude of 3I2 injection to determine when it is safe to enable protection elements that rely on negative-sequence quantities may not be as effective in the future. We do not know at this point how newer IBRs will respond during the first few cycles after a fault.

VIII. Conclusion

Current differential schemes offer extraordinarily selective pickups for their zones of protection. They extend the possibilities of not having to be coordinated with adjacent zones of protection. Nearly all 87L applications can follow typical setting calculation procedures, determine the dependability and security limits, then choose a pickup lower than the two, whereas current different schemes can still be applied to transmission lines with one or more tap load transformers on the line. Additional checks can be applied to ensure pickups are validated against possible inrush current and overreaching for external faults on the low side of the transformer.

Three-terminal line protection can be challenging due to the wide range of conditions that need to be simulated. Compromises to the standard reach guidelines may need to be considered for the protective elements to cover the length of the transmission line. Compared to two-terminal lines, additional consideration must be given to the communication scheme applied because many standard assumptions do not apply to three-terminal lines.

This paper examined SIR in more detail than the original paper. It provides guidance on how much to pull the reach back for lines with high SIR as well as more guidance on when to turn off underreaching distance elements. In line applications with high SIR only during N-1 conditions, fault detectors can be used to allow underreaching distance protection when the system is normal and block it only during the times when the system is weak and security may be compromised. This approach provides a better compromise between security and dependability.

The SOTF scheme serves two main purposes: protection for closing into a zero-voltage fault and high-speed protection for the entire length of the line when closing into a faulted line. Including 27P supervision of a 50P element allows the engineer to set the pickup without regard for load. New guidelines for setting the 50P and 27P elements ensure coverage of the entire line for balanced faults and complement the overreaching elements to provide fast and dependable protection. Similarly, using non-directional (offset) distance elements can simplify SOTF protection. Offset distance elements are easy to set. They include the origin in the tripping characteristic and do not require healthy voltage to operate. For this reason, they are dependable and fast during SOTF conditions.

An LOP overcurrent element is a dependability oriented solution that enables the relay to protect against fault even during an LOP condition. The element can be applied with a brief definite time delay to allow for neighboring protection zones to clear faults. The fact that this element is only enabled under N-1 conditions allows the protection engineer to make compromises that cannot be considered for other forms of protection.

IBRs are becoming more prevalent on the BES. These sources often suppress negative-sequence current injection and the quantities that they do inject are often incoherent with the negative-sequence voltage. For line terminals that can be sourced by IBRs under N-0 or N-1 conditions, protective elements based on negative-sequence quantities can have security issues. Using zero-sequence polarization is recommended over negative-sequence polarization for ground directional elements. However, negative-sequence quantities are also used in the distance element FIDS logic. The paper discusses recent recommended practices for setting negative-sequence fault detectors based on the capacity of the IBR sources behind the line terminal to prevent operation on negative-sequence quantities from poorly behaving IBRs [11].

A wide variety of line protection topics were discussed and dissected in this paper and the previous paper. The papers focused on the practical decisions and compromises that need to be made by the protection engineer setting the line relay. The authors also intended to inform the reader about the reasoning for why cookbook guidelines exist, and when they need to go beyond them. The topic of transmission line protection is broad, and potential future developments in line protection ensure that there will always be more to discuss.

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