More Impedance, Mho Problems – Protecting Transmission Lines With In-Zone Series Reactors

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Abstract—**Series reactors are used in transmission lines to limit load flow or fault currents, or both. The impedance of these reactors can be equal to several multiples of the transmission line impedance. The inclusion of a series reactor in the transmission line zone of protection affects the impedance profile of the line and requires additional considerations. This includes setting distance elements to be secure and dependable when the reactor is in service or bypassed, and to ensure that the line relays also provide adequate protection for reactor faults. In this paper, we discuss why series reactors are used in transmission lines, the construction of series reactors, and their impact on transmission line protection and fault location algorithms. We explain the best practices to program mho distance elements, directional elements, line current differential protection, and pilot schemes to protect lines with series reactors, and we explore their effectiveness in detecting reactor faults. Finally, we explain how to calculate a more accurate fault location using programmable relay logic.**

I. INTRODUCTION

A transmission line with a series reactor is a form of compensated transmission line. Compensated lines can further be split into series compensated and shunt compensated. A much more common version of a series compensated line uses series capacitors to increase the load carrying capability of a line. Introducing a large series capacitance on a system that is generally inductive in nature can create many protection challenges, and protection relays have specific algorithms to address these challenges. As such there is an abundance of information available on this topic, and relays even have specific settings for series capacitor compensated lines. Series reactor compensated lines are much less common but are still a subset of compensated lines. They are so uncommon that very little literature exists on protecting lines with series reactors. It is much more common for reactors to be used to prevent system overvoltage via shunt compensation.

Series reactors are inductors that are added to a transmission line to reduce fault currents under short-circuit conditions or to limit load flow under steady-state conditions. A series reactor is used to limit the fault current when the magnitude is too close to the circuit breaker interruption rating. It can also be used to limit load flow through a transmission line to ensure that load is distributed equally through all parallel paths in a transmission network [1] [2].

Series reactors are typically installed at one end of a transmission line inside the substation. A bypass breaker or switch is connected parallel to the reactor. This switch or breaker can be opened to place the reactor in service or closed to bypass the reactor. Although there are several types of reactors that are used for shunt reactor applications, air-core dry-type reactors are widely used in series reactor applications.

Most utilities use their standard protection design for lines with series reactors. This may include standard current transformer (CT) and voltage transformer (VT) locations along with the same line protection relays that are used for traditional transmission line protection applications. However, the location of CTs and VTs and the choice of protective relays must be carefully considered in a series reactor application.

Our paper is organized as follows. The classification and construction of reactors is discussed in Section II. The location of CTs and VTs, and CT sizing considerations are discussed in Section III. Using cookbook settings for transmission line relays may not provide sufficient coverage for faults on the transmission line and the reactor. The impact of the reactor on phase and ground distance and directional elements is discussed in Section IV. The fault location reported by the line relays will have an error due to the series reactor impedance, and we discuss methods to obtain accurate fault location in Section V. Additional protection elements such as breaker failure, breaker flashover, and turn-to-turn faults are discussed in Section VI.

II. CONSTRUCTION OF SERIES REACTORS

There are several types of reactors that are used in transmission line applications, and they can be classified as follows [3]:

1. Dry-type or liquid-immersed
2. Air-core or gapped iron-core

The type of construction chosen for any given application will depend on factors such as voltage level, power rating, physical space constraints, and cost. Dry-type air-core reactors are a simple, cost-effective, low maintenance option for various applications, but have space constraints. They are often used as series reactors on the transmission system. One characteristic of dry-type air-core reactors that makes them especially suitable for use in series applications is that they do not have an iron-core that can saturate. Iron-core reactors can saturate because of high currents, which will reduce the overall impedance of the reactor and make it less effective at reducing fault currents. Air-core reactors cannot saturate because of the absence of an iron-core and are the best choice for fault limiting series reactor applications because their impedance does not decrease during faults.

Air-core dry-type reactors can be used in series reactor applications for a wide range of voltages from 1.2 kV–

765 kV [4]. Dry-type reactors are preferred over liquid-filled reactors because there is no risk of liquid leakage or explosions. These reactors are easier to construct and maintain. However, air-core dry-type reactors take up more space compared to liquid-immersed reactors because of additional clearance requirements.

Air-core dry-type reactors do not have a magnetic core to "contain" the magnetic field produced by the reactor. The magnetic field will flow through as much air as possible for a given magnetomotive force. The field produced by this type of reactor can induce currents in nearby conductive materials, such as metal fencing, metal structures, and even rebar that is embedded in concrete. Studies must be performed to ensure that sufficient clearance is provided to avoid safety and structural hazards caused by these induced currents. All parts of the reactor are energized at line potential. This means that proper electrical and magnetic clearances must be provided between the reactor and other equipment or personnel [5]. The minimum clearance values are typically provided by the reactor manufacturer.

Fig. 1 shows a single phase of an air-core dry-type series reactor installed at an Oncor substation.

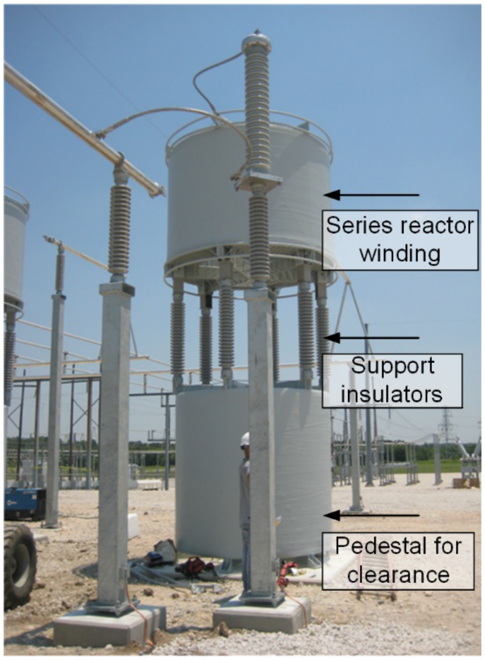

Fig. 1 Air-core series reactor installed at 138 kV substation

III. INSTRUMENT TRANSFORMER CONSIDERATIONS

Fig. 2 shows a simplified one-line diagram with options for CT and VT locations for the relay at the reactor terminal. While only one set of CTs and VTs are typically used to protect both the series reactor and the transmission line, there are benefits to using CTs and VTs on both the bus side and line side to optimize protection for both zones.

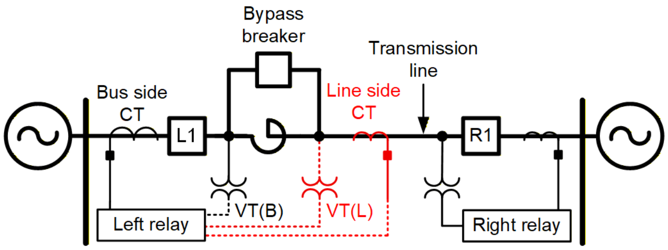

Fig. 2 CT and VT connection options

A. *CT Placement Considerations*

The bus-side breaker is typically used to provide isolation for faults on the reactor and on the transmission line. There is typically no breaker on the line side of the reactor, and as a result, breaker bushing CTs are not available on the line side of the reactor. Additionally, at transmission-level voltages, it is costly to install freestanding CTs on the line side of the reactor to provide reactor differential protection. Because of this, line-side CTs may not be available. While line-side CTs are not required, having these CTs does provide advantages.

With bus- and line-side CTs, it is possible to implement differential protection for the reactor (87X). If there is no line current differential protection (87L), the 87X is particularly useful to reduce reliance of distance and directional overcurrent protection to detect reactor faults. However, even if 87L is available, the 87X is still useful because it provides a reliable way to determine the faulted zone (reactor or the line). This can be used to prevent reclosing on reactor faults, if desired. Fig. 3 shows the preferred 87L and 87X zones of protection if each is available. Both 87L and 87X are blind to reactor turn-to-turn faults. Turn-to-turn fault detection is covered in a later section.

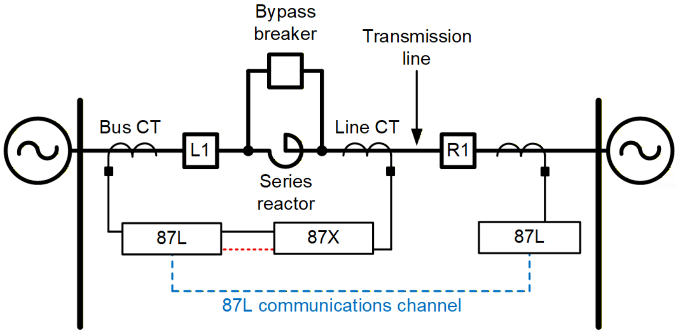

Fig. 3 Preferred 87X and 87L configuration

When a reactor fault occurs, both the L1 and R1 breakers must open. The 87L relays will open L1 and R1 for reactor faults as well as line faults. The 87X relay, however, requires direct transfer trip (DTT) communications to open R1 for reactor faults. Without DTT, the 87X still provides fast identification of whether the fault is in the reactor or the line. By using bus-side CTs for 87L, and overlapping 87L and 87X, we reduce 87X reliance of DTT to effectively clear reactor faults while still gaining benefit from the addition of 87X.

In Fig. 3, an optional connection (shown in red) from the line-side CTs is shown also going to the 87L. This connection allows reactor differential protection to be implemented in the 87L relay to provide backup to the dedicated 87X relay. This functionality can be added through custom relay logic [6].

In breaker-and-a-half or ring-bus configurations, the 87L relay should be connected to CTs from the two breakers on the bus side to provide the maximum restraint signal to the algorithm for external fault security. Because line current differential relays often have only two sets of current inputs, it is not recommended to parallel the CTs from the two breakers to free up one set of current inputs required for the line-side CTs (shown in red in Fig. 3) [7]. In breaker-and-a-half and ring-bus configurations with a line current differential relay, the best performance can be achieved with a dedicated 87X relay with three current inputs, while only implementing 87L protection in a dedicated line protection relay via the two breaker CTs on the bus side of the reactor. If 87L is not available and impedance-based protection is primarily being used, then paralleling the two breaker CTs and implementing 87X in custom relay logic in the line relay is a viable option.

B. CT Sizing Considerations

Series reactors increase the X/R ratio of the system, which increases the time a dc offset is present during shunt faults on the system. DC offset in the current signals during faults can push CTs into saturation, especially if the fault remains for an extended period of time. However, when the series reactor is in service, fault current contribution will be limited. This helps prevent CT saturation. In effect, there are two cases to analyze for CT performance:

- External fault with bypass breaker closed—high fault currents, lower X/R ratio.
- External fault with bypass breaker open—lower fault currents, higher X/R ratio.

Reference [8] provides guidance on CT selection and can be used to evaluate these two cases.

C. VT Considerations

The location of the VTs will affect the performance of impedance-based functions such as distance protection, fault location, and to some extent, impedance-based directional elements. In this section we will discuss using the bus-side VT connection, VT(B), versus the line-side VT connection, VT(L), shown in Fig. 2.

Using bus-side CTs and VTs allows the current measurement point and the voltage measurement point to be located at the same electrical location and provides a relatively straightforward impedance calculation regardless of if the fault is in the reactor or on the line. However, the series reactor and transmission line creates an effective non-homogeneous line, which will lead to sacrifices in impedance-based functions as we will discuss. Further, when the reactor is bypassed, the reliability of the impedance-based functions is significantly affected. The relay settings may need to be adjusted based on the bypass breaker status.

Using bus-side CTs and line-side VTs places the reactor in between the current measurement point and the voltage measurement point. This makes the apparent impedance measurement for reactor faults more complex to determine and requires further study. However, this VT location significantly reduces complexity for impedance-based elements for line faults, which includes no longer needing the status of the bypass breaker for impedance-based element reliability. Further, as we will see, this connection still offers reactor protection.

IV. TRANSMISSION LINE PROTECTION

Many protection schemes for transmission lines rely on impedance-based functions, such as phase and ground distance. Directional relaying may also be based on impedance calculations. Series reactors can have a significant impact on the impedance of a protected line. In turn, this will affect the performance of any impedance-based function in the line relaying. In this section we discuss the effects of series reactors on phase and ground distance elements, directional relaying, and the impact of VT location.

In this section, we define factor "m" as the per unit location of a fault in each segment of the zone of protection. We define $m_{ZX} = 0$ for a fault on the bus side of the reactor and $m_{ZX} = 1$ for a fault on the line side of the reactor. Similarly, we define $m_{ZL} = 0$ for a fault on the left terminal of the line segment (the line side of the reactor) and $m_{ZL} = 1$ for a fault on the right terminal of the line segment.

A. Positive Sequence Impedances of Reactors and Transmission Lines and Phase Distance Relay Considerations

A transmission line positive-sequence impedance is determined by many factors including conductor size and bundling, construction, and spacing. The positive-sequence impedance of a transmission line will have an X/R ratio that is significantly lower than the positive-sequence impedance X/R ratio of a reactor. The X/R ratio of a transmission line is typically less than 14. For an air-core reactor this is typically 350 [9]. The difference in X/R ratios results in a difference in the positive-sequence impedance angle between the two zones. Additionally, the reactor impedance is concentrated at one end of the line, whereas the transmission line impedance is distributed along the line length. This adversely affects fault location and impedance measurement for faults within the reactor and on the line because the effective positive-sequence line angle varies with fault location.

1) Line Faults

In this section, we focus on line protection using distance elements and compare the bus-side VT and line-side VT location selection. Fig. 4 shows a sample system with the following system parameters in per unit:

- Positive-sequence sending source impedance:
  - $ZS1 = 0.2 \angle 80$
- Positive-sequence reactor impedance:
  - $ZX1 = 1.6 \angle 90$

- Positive-sequence line impedance:
  - $ZL1 = 1 \angle 70$
- Positive-sequence receiving source impedance:
  - $ZR1 = 0.2 \angle 80$
- Zero-sequence line impedance:
  - $ZL0 = 3 \angle 70$

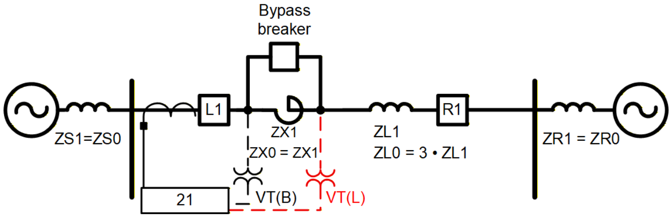

Fig. 4 Sample system

In general, distance elements are set as a percentage of the total impedance of the line they will protect. For a Zone 1 element a common security percentage to use is 80 percent. Using this as guidance we arrive at the following settings based on the VT location, where 21PB is a phase distance element using bus-side VTs, and 21PL is a phase distance element using line-side VTs:

- $\text{Reach}_{21PB} = 0.8 \cdot (ZX1 + ZL1) = 2.05 \angle 82.33$
- $\text{Reach}_{21PL} = 0.8 \cdot (ZL1) = 0.8 \angle 70$

Fig. 5 shows the positive-sequence memory polarized mho characteristics for 21PB and 21PL with a fault placed at 0.46 pu of ZL1. For easy comparison between the two characteristics, the origin (0,0) is fixed at the line VT location. Therefore, 21PB has its position and apparent impedance measurement shifted by –ZX1. The 21PL mho expands back to ZX1 + ZS1. The 21PB mho expands back to ZS1, but in Fig. 5 it expands back to ZX1 + ZS1 as well based on the shifting of the characteristic by –ZX1.

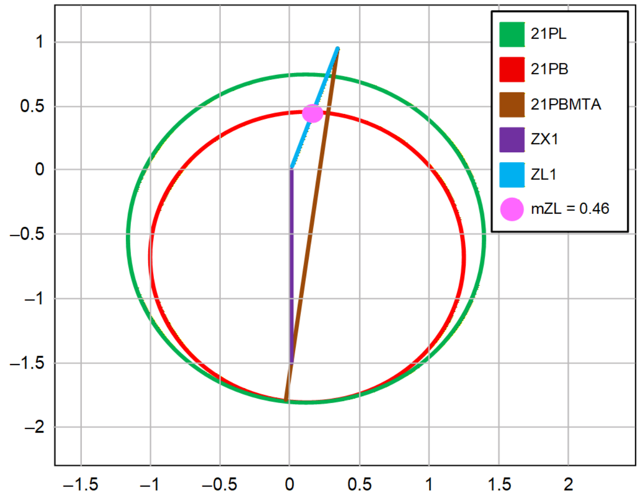

Fig. 5 Apparent impedance for a three-phase fault

21PB protects less of the line than 21PL with these settings. 21PB reaches 0.46 pu of the line impedance while 21PL reaches 0.8 pu of the line impedance. However, we ask, does the VT location affect how close to the remote line terminal Zone 1 can reach?

A secure Zone 1 reach setting is heavily influenced by ratio errors and fixed steady-state errors. Ratio errors include VT ratio errors, CT ratio errors, and impedance measurement errors. They are proportional to the quantity you are measuring, which in this case is impedance to the fault. In general, it is accepted that the ratio error alone necessitates reducing Zone 1 reach by at least 10 percent from the theoretical maximum of 100 percent of the total line impedance. In systems with high source impedance ratio (SIR), fixed steady-state errors of the VT become significant and require further reducing Zone 1 reach to maintain security [10]. Higher SIRs lead to lower available voltage for faults, which makes any inherent voltage measurement errors more likely to challenge Zone 1 security. Additionally, high SIRs amplify transient overreach issues that are common in capacitive voltage transformers (CVTs). Many relays have internal logic to mitigate these transients by identifying they are occurring and delaying Zone 1 until the transient has subsided. In contrast, a low SIR gives the relay more voltage to work with to overcome any voltage measurement errors. Fig. 6 shows the measured relay voltage for faults along ZX + ZL shown in a per unit fault location ($m_{ZX + ZL}$). A fault at m = 0.62 represents a fault at the line-side VT location. There is significantly more voltage available for a line-end fault at the bus-side VT location over the line VT location.

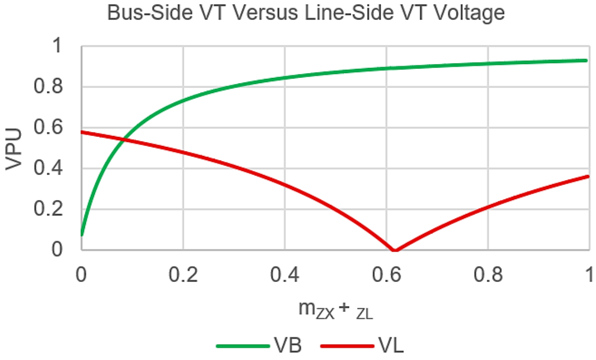

Fig. 6 VT(B) and VT(L) voltages

We define the 21PB SIR as SIR_B and 21PL SIR as SIR_L for phase faults, as shown in (1) and (2). In a real transmission network, there will be a transfer impedance between the left bus and the right bus; and calculating SIR should be done using voltages from a fault study program as described in [10]. However, in this example system, there is no transfer impedance, so the SIR_B and SIR_L values can be found simply by taking the proper impedance ratio.

$$SIR_B = \frac{ZS1}{ZX1 + ZL1} \tag{1}$$

$$SIR_L = \frac{ZS1 + ZX1}{ZL1} \tag{2}$$

Reference [11] provides guidance on how to limit Zone 1 per unit reach as a function of ratio error, SIR, and expected voltage measurement error (V_{ERR}), as shown in (3) and (4). We selected a ratio error of 10 percent and a very conservative V_{ERR} of 3 percent.

$$Reach(PU)_{21PB} = 1 - Ratio_{ERR} - V_{ERR} \cdot \left(SIR_B + 1\right) \tag{3}$$

$$Reach(PU)_{21PL} = 1 - Ratio_{ERR} - V_{ERR} \cdot \left(SIR_L + 1\right) \tag{4}$$

From (3) and (4) we arrive at a per unit reach of 0.86 for a bus-side VT location and 0.81 for a line VT location.

Next, we multiply the per unit reach by the proper impedance to get the reach setting, as shown in (5) and (6).

$$Reach_{21PB} = Reach(PU)_{21PB} \cdot \left(ZX1 + ZL1\right) \tag{5}$$

$$Reach_{21PL} = Reach(PU)_{21PL} \cdot \left(ZL1\right) \tag{6}$$

From (5) and (6), we arrive at a secure reach from the bus-side VT location to be 2.2 ∠ 82.3, and at the line VT location to be 0.81 ∠ 70. To better compare the reaches of each element, we adjust the bus-side VT reach to show how it compares with the line-side VT reach, as shown in (7).

$$Reach_{21PB(Adjusted)} = Reach_{21PB} - ZX1 \tag{7}$$

In our numerical example, (7) evaluates to 0.65 ∠ 63. The line VT location reaches approximately 0.16 pu of ZL1 farther than the bus-side VT location once adjusting for reactor impedance.

Appendix A shows that the line VT Zone 1 can reach $Ratio_{ERR}$ • ZX1 farther than the bus-side VT Zone 1. This answers our initial question that, yes, the VT location does affect coverage for line faults, with the line VT location being the favorable location. The result of this is shown in Fig. 7.

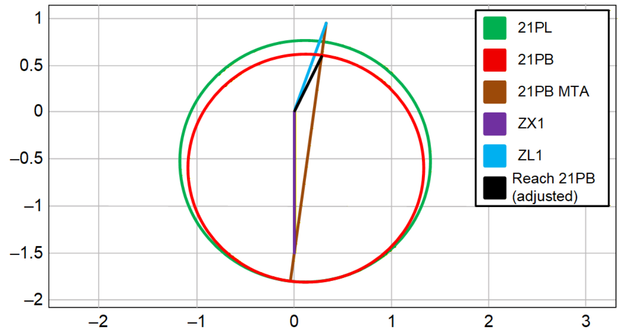

Fig. 7 Optimized phase reach setting for 21PB

When memory expires, the expansion affects the 21PL relay more than the 21PB relay, shown in Fig. 8.

While the resistance coverage of 21PL does reduce relative to 21PB for some line faults, the effects would only be present for faults that are cleared with a time delay. An underreaching Zone 1 and an overreaching Zone 2 pilot zone would not be affected much as the memory does not decay completely within the operation time of these elements.

A minor complication that arises from the use of 21PB is the conflict of setting an ideal maximum torque angle (MTA) because it varies based on fault location. In this example, the selected MTA for Zone 1 is the MTA for the entire ZX1 + ZL1 impedance, which is 82.3. However, for faults near the line VT location, the ideal MTA is closer to 90 degrees. We point out the following relationship to be aware of: selecting an MTA that is greater than or less than the true MTA at the reach point will lead to underreach. Using MTA = ang(ZX1 + ZL1) will allow the Zone 2 element to have ideal reach for line-end faults while leading to a slight underreach for the Zone 1 element. This biases Zone 1 towards security and the Zone 2 element toward dependability, which is desirable.

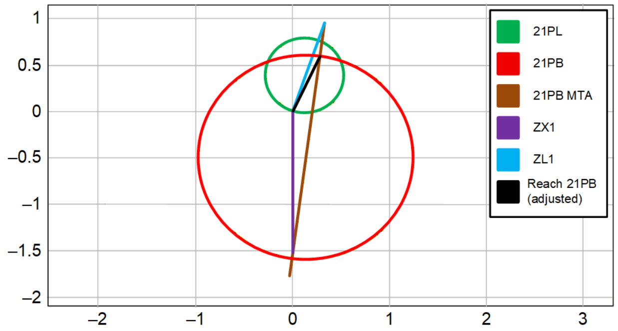

Fig. 8 21PL and 21PB characteristics when V1MEM expires for a three-phase fault

2) *Reactor Faults*

Based on the previous setting recommendations for 21PB and 21PL, 21PB will operate for phase faults within the reactor as they clearly fall within the forward reach of the element. However, the 21PL response is not easily determined because the voltage measured by 21PL for a bolted reactor fault is a function of ZR1, while the measured current is a function of ZS1, given the CT location (see Fig. 4). As such, the apparent impedance calculation for 21PL for a reactor fault is more complex than 21PB. The formula for the apparent impedance for a three-phase fault on the reactor ($0 <= m_{ZX} <= 1$) is shown in (8). The derivation for (8) is provided in Appendix B.

$$Z_{21PL(Reactor)} = \frac{\left(1 - m_{ZX}\right) \cdot ZX1 \cdot \left(ZS1 + m_{ZX} \cdot ZX1\right)}{ZR1 + ZL1 + \left(1 - m_{ZX}\right) \cdot ZX1} \tag{8}$$

Based on the sample system parameters, Fig. 9 shows the impedance trajectory for three-phase reactor faults, as seen by 21PL. To obtain this plot, the value for m_{ZX} was varied from 0 to 1, which assumes shunt reactor faults can occur at any location within the reactor, not just near the reactor terminals. A self-polarized mho is shown for 21PL as a reference because the mho elements expansion is variable based on the fault location. The self-polarized representation is conservative in that the true characteristic will always be larger than depicted for fast operating zones.

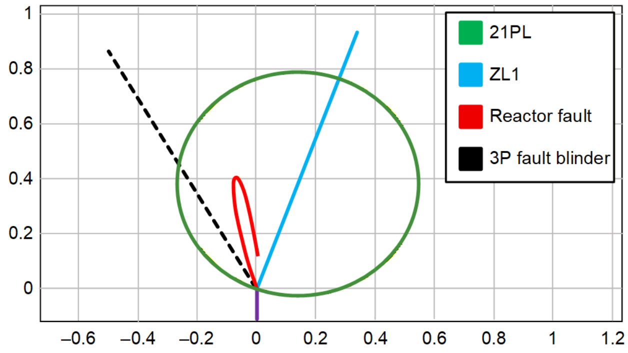

Fig. 9 21PL apparent impedance trajectory for bolted three-phase reactor faults

Perhaps surprisingly, 21PL will operate for all bolted three-phase reactor faults. However, there are some things to be aware of. First, some relays have a built-in blinder at 120 degrees to prevent phase distance element operation for reverse three-phase faults with fault resistance [12]. In this example, the impedance trajectory for reactor faults is in Quadrant 2, but still within the operate region of the blinder. In general, this blinder should not restrict operation for three-phase faults.

Second, if the ratio of ZX1 over ZL1 becomes too large, then some reactor faults will fall outside of 21PL Zone 1. For example, assume the same system, but double the ZX1 impedance (3.2 ohms). Fig. 10 illustrates that for faults between $m_{ZX} = 0.3$ and 0.9 that a self-polarized 21PL element will not operate on Zone 1.

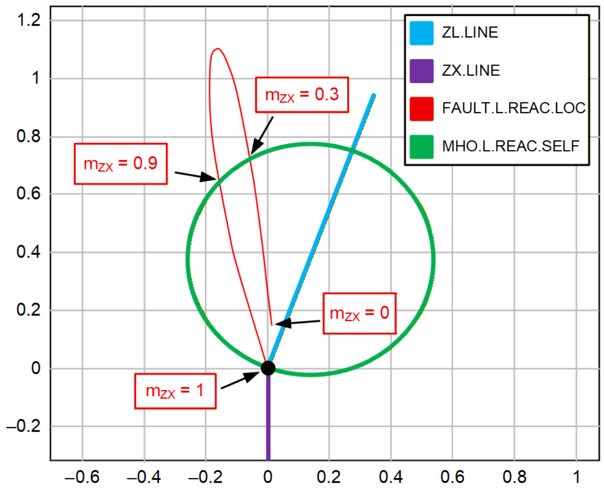

Fig. 10 21PL reactor faults with high ZX1 to ZL1 ratio

For ang(ZL1) greater than 70 degrees, (9) provides a simple way to determine if the reactor is covered for phase faults that occur at any location within the reactor by Zone 1 set with a reach of 80 percent of ZL1. See Appendix C for more details.

$$\frac{ZX1 + ZS1}{ZL1} < 2.2 \tag{9}$$

For example, if the source impedance is 0.2 pu of the line impedance, the reactor impedance can be up to two times the line impedance and 21PL will protect the reactor for any phase fault location within the reactor. When evaluating (9), ensure that you are using the maximum ZS1 under reasonable contingencies when the reactor is in service.

Phase faults at locations other than $m_{ZX} = 0$ and $m_{ZX} = 1$ should be very unlikely because the reactor spacing should essentially eliminate multiphase faults at other reactor locations as a possibility. Fault locations at $m_{ZX} = 0$ and $m_{ZX} = 1$ represent multiphase faults at the terminals of the reactor where the bus and line conductors can still be close enough for this fault type to occur. 21PL will be dependable for $m_{ZX} = 1$ because this represents a traditional close-in fault from the perspective of 21PL.

We can simplify (8) further for $m_{ZX} = 0$ and $ZR1 = 0$ and arrive at (10) to ensure that 21PL is dependable for a fault on the bus side of reactor.

$$\frac{ZS1 \bullet ZX1}{ZL1 + ZX1} < REACH_{21PL} \tag{10}$$

Equation (10) is more lenient in the allowable ratio of ZX1 over ZL1 than (9) because dependability for a phase fault within the reactor is ignored.

B. *Zero-Sequence Impedances of Reactors and Transmission Lines and Ground Distance Relay Considerations*

The difference in the zero-sequence impedance of the reactor and line is significant. Transmission lines have strong mutual coupling between phases that lead to a zero-sequence impedance that is higher than the positive-sequence impedance. To account for this difference in positive- and zero-sequence impedances, a k0 factor is included in ground impedance elements to calculate an apparent impedance to the fault that is equivalent to the positive-sequence impedance. This k0 factor can vary based on many factors, but for simplification we will assume that our transmission line has a zero-sequence impedance that is three times the positive-sequence impedance, as shown in Fig. 4. This leads to a k0L factor of 2/3, as shown in (11).

$$k0L_{21GL} = \frac{ZL0 - ZL1}{3 \bullet ZL1} = \frac{3 \bullet ZL1 - ZL1}{3 \bullet ZL1} = \frac{2}{3} \tag{11}$$

In contrast, the reactor has a positive-sequence impedance and zero-sequence impedance that is equal. This leads to an equivalent k0 factor of the reactor (k0X) of 0.

1) *Line Faults*

A 21GL (21 ground with line-side VTs) can have the k0L factor set as shown in (11) and acquire good reliability for line faults; it does not need to be adjusted based on reactor bypass position.

A 21GB (21 ground with bus-side VTs) will suffer because the k0 factor required for accurate impedance measurement will change based on the fault location. Selecting a k0 factor that is too large will lead to relay overreach, while selecting a k0 factor that is too small will lead to relay underreach.

To optimize the k0 factor for a 21GB Zone 1 element it is ideal to set the k0 factor based on a desired reach point on the line. We take the value from (7) and convert it to per unit of the line impedance using (12).

$$Reach(PU)_{21PB(Adjusted)} = \left| \frac{Reach_{21PB(Adjusted)}}{ZL1} \right| \tag{12}$$

Then we take the per unit line reach and calculate the k0 factor at the reach point. A derivation for (13) is provided in Appendix D. In our numerical example, $Reach(PU)_{21PB(Adjusted)}$ evaluates to 0.65, meaning that the bus-side VT location 21GB reaches approximately 65 percent of the line ZL.

$$k0L_{21GB} = \frac{ZL0 \bullet Reach(PU)_{21PB(Adjusted)} - ZL1 \bullet Reach(PU)_{21PB(Adjusted)}}{3 \bullet (ZL1 \bullet Reach(PU)_{21PB(Adjusted)} + ZX1)} \tag{13}$$

In our numerical example, (13) evaluates to 0.195 ∠ –14.26. For faults beyond 65 percent of ZL1, the true k0 factor will be larger than k0L, providing additional security. For faults less than 65 percent of ZL1, the true k0 factor will be smaller than k0L, providing more sensitivity. By selecting the k0 factor based on the reach point, the reliability of the 21GB element is optimized.

The k0 factor for the entire ZX + ZL zone evaluates to 0.26 ∠ –12.33. This larger k0 factor is not as secure as the k0 factor used in (13), but it is more dependable and ideal for Zone 2 elements. Many distance relays do allow for separate k0 factors for the various zones of protection. If a single k0 factor is used for both Zone 1 and Zone 2, then consider using (13) for the k0 factor and increase dependability margin factors for Zone 2.

When the reactor is bypassed, the k0 factor should be changed to (11) to provide accurate apparent ground fault measurements.

2) Reactor Faults

For phase-to-ground faults, 21GB will operate because the reactor is clearly within the reach of the element. Again, the 21GL element is not as straightforward. However, the 21GL will see an even smaller apparent impedance for ground reactor faults than the 21PL does for phase faults. This is because for reactor faults, the selected k0 factor is larger than the true k0 factor. Phase-to-ground faults at various points on the reactor winding (fault locations from $0 < m_{ZX} < 1$) are unlikely. Using the guidance provided in (9) and (10) will ensure phase-to ground fault coverage for reactor faults based on the ratio of ZX1 over ZL1.

C. Oncor System Results

The system shown in Fig. 11 was used to test 21PB and 21PL for phase and ground faults based on the discussion in the previous sections. This system is based on an actual 138 kV transmission line in Oncor’s network. A 40.85-mile transmission line with a series reactor at the left terminal was modelled in a real-time digital simulator (RTDS). The analog interface of the simulator injects currents and voltages into the left and right relays.

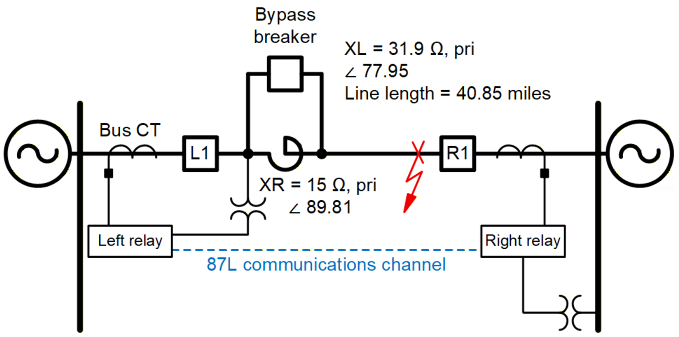

Fig. 11 Test system

The Zone 1 reach of the 21PL and 21GL was set to 80 percent of ZL1. The Zone 1 reach of the 21PB and 21GB was set to 76 percent of ZL1, which equates to 83 percent of ZX + ZL. The transmission line begins at a $m_{ZL+ZX} = 0.32$.

Faults were simulated along the reactor and the transmission line, and the fault resistance was increased. The response of the Zone 1 element was recorded. Fig. 12 shows the maximum fault resistance value for which Zone 1 was still able to operate for various fault types along the reactor and transmission line.

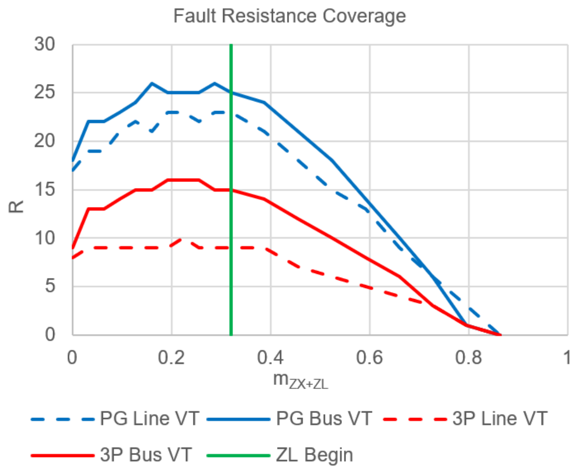

Fig. 12 Fault resistance coverage for Oncor example line

The bus VT location offers more fault resistance coverage for a majority of the zone, but as the fault location is moved down the line, the fault resistance coverage of the line VT location becomes better. Further, the line VT location offers adequate fault resistance coverage for reactor faults.

D. Directional Element Behavior for Shunt Faults Based on VT Location

Many relays use an impedance-based directional element that allows a user to set impedance thresholds to adjust the sensitivity of the directional element [13]. These directional elements operate on either negative-sequence quantities (32Q) or zero-sequence quantities (32V). They are used to supervise overcurrent protection and, in most cases, supervise the distance elements.

1) Bus-Side VT Recommendation

With a bus-side VT, the element will work as expected and report approximately $-|ZS_{2,0}|$ for a forward fault and $|ZR_{2,0} + ZL_{2,0} + ZX|$ for a reverse fault when the reactor is in service. Note that a subscript 2 should be used in all impedance variables (e.g., $ZS_{2,0}$) while evaluating 32Q elements, and a subscript 0 should be used while evaluating 32V elements. There will be slight variations as the MTA selected will not exactly match the measured impedance for forward AND reverse faults because of the difference in angle between forward and reverse faults. A forward threshold must be set greater than $-|ZS_{2,0}|$ for dependable forward declaration for faults in the reactor and on the line. A reverse threshold must be set less than $|ZR_{2,0} + ZL_{2,0}|$ for dependable reverse declaration for faults behind the relay when the reactor is bypassed. By default, most impedance-based directional elements have a small negative threshold that must be overcome for forward fault declaration and a small positive threshold that must be overcome for reverse declaration.

Ensure that an adequate dependability margin factor is used. For example, with bus-side VTs, dependable settings are:

- Forward threshold minimum = $0.5 \bullet -|ZS_{2,0}|$
- Reverse threshold maximum = $0.5 \bullet |ZL_{2,0} + ZR_{2,0}|$
- Set MTA_2 and MTA_0 based on $ang(ZL_{2,0}+ZX)$

In general this will provide the most benefit for all protection algorithms that use these settings.

2) *Line VT Recommendation*

With a line VT location, the negative- or zero-sequence impedance seen for a fault on the line with the reactor in service will be $-|ZS_{2,0} + ZX|$. A reverse fault will be $|ZR_{2,0} + ZL_{2,0}|$. With the reactor bypassed, the forward impedance is $-|ZS_{2,0}|$. However, faults in the reactor create a variable negative-sequence impedance value based on fault location in the reactor, but it is always negative, which is what we expect for forward faults. Fig. 13 shows the apparent Z2 impedance for faults between $m_{ZX} = 0$ and $m_{ZX} = 1$. For a fault at $m_{ZX} = 0$, the I2 current is large and the V2 voltage is small creating a small value for Z2. This is the worst case for forward fault dependability, so a dependability-biased threshold was selected (see AUTO4 from [13]). The forward threshold is set as a small positive value to ensure the very small negative impedance is dependably declared forward. A fault at $m_{ZX} = 1$ creates a large V2 and a small I2, leading to a large magnitude of Z2. This fault is still well below the selected forward directional threshold.

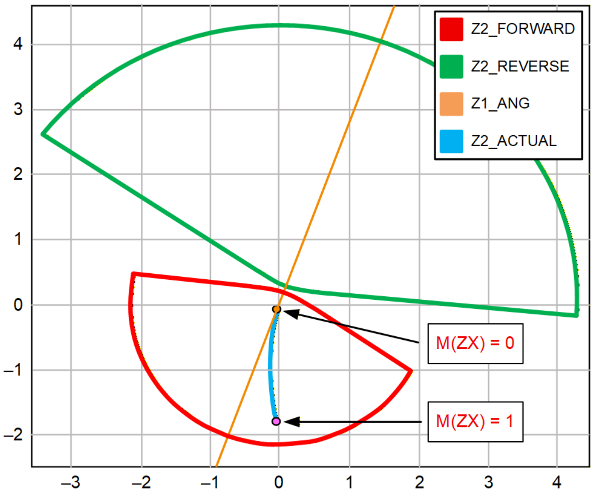

Fig. 13 Z2 impedance for reactor faults with line VTs for sample system

Again, with reactor fault and line-side VTs, sequence impedance varies based on fault location because the CT and VT are not connected at the same electrical point. A variable Z2 and Z0 impedance relative to forward fault location is unique to this VT and CT arrangement. In this example, we assumed the boundary condition that ZR was = 0 in our sample system, which reduces the amount for V2 available at the line VT for reactor faults. Setting recommendations for 32Q and 32V for line-connected VTs follows:

- Consider using forward dependability-biased thresholds for ease (AUTO4). This sets a forward threshold to a small positive number (i.e., + 0.2 ohms)
- Alternatively, find the minimum $|ZS_{2,0}|$ for forward line fault with the reactor bypassed and a close-in reactor fault with the reactor in service. If this minimum value is less than two times the default threshold value, then use dependability-biased thresholds. Otherwise use a 0.5 dependability factor margin to set the forward thresholds at $-0.5 \bullet \min |ZS_{2,0}|$
- Set the reverse threshold lower than $0.5 \bullet |ZL_{2,0}|$. Set MTA_2 and MTA_0 based on $ang(ZL_{2,0})$.

E. *87L Considerations*

A line current differential relay that includes the reactor and the line is ideal to protect the entire zone and is preferred over relying solely on impedance-based protection. In any 87L scheme it is preferred to prevent paralleling of CTs to ensure the 87L algorithm has access to all currents to develop a strong restraint signal for external faults [14]. In applications with series reactors, the X/R ratio will be much higher than typical applications and CT saturation for external faults is a concern. As these applications can have a higher likelihood of CT saturation, using an 87L relay with a separate CT input for each CT that bounds the zone of protection is recommended.

Reactor bypass breaker operation will not affect the 87L zone of protection, so no additional consideration is required for bypass breaker operation. Select appropriate 87L characteristic settings based on CT sizing and system parameters. Reference [15] provides guidance for 87L relays that use an alpha plane characteristic.

F. *67G Overcurrent Considerations*

In POTT and DCB schemes, a sensitively set 67G (directional ground overcurrent) element is sometimes used for sensitive ground fault protection. This can be in addition to or in lieu of 21G protection. In Appendix C we explain how 67G can possibly be used to detect reactor turn-to-turn faults. However, unequal pole closing or opening of the bypass breaker will look like internal faults to a POTT and DCB scheme with a sensitively set 67G. There are a few options to implement a secure 67G element in communications-assisted tripping schemes with a reactor bypass breaker. The first option is to raise the 67G pickup above the maximum load current with a security margin. This will significantly reduce the sensitivity for high resistance ground faults but will allow for fast line clearing for many ground faults within the zone. The second option is to delay the sensitively set 67G with a short time delay (i.e., 3 cycles) to ride through pole discordance. This option provides more sensitivity but can lead to unneeded delays for ground faults with little fault resistance.

The third option is to implement two levels of 67G protection. The first level is a 67G2 that has no intentional delay and is set at 150 percent of the maximum expected load. This provides security under maximum load conditions in which a pole discordance exists. If you are also implementing 21G protection, then this high-set 67G2 element may be considered optional. The second level is a 67G4T that is set sensitively (i.e., 10 percent of nominal CT rating), but has a three-cycle time delay to prevent false operation during pole discordance. In a DCB or hybrid POTT scheme, tripping will occur if 67G2 or 67G4T asserts at one terminal and a reverse-looking sensitively set 67G3 (i.e., 5 percent of nominal CT rating) does not assert at the other terminal. When the communication channel is available, the echo logic in hybrid POTT schemes makes them behave very similarly to DCB schemes [16].

G. *Remote Terminal Considerations*

When the reactor is in service, the remote terminal can have a Zone 1 distance element reach into the reactor providing 100 percent line fault coverage from the remote end. To open the local terminal for faults outside its reach, a DTT signal needs to be available. When the reactor is bypassed, the reach of the remote end relay will need to be adjusted via custom relay logic to pull the reach back.

While this is feasible, there is no inherent advantage to this scheme over a POTT or DCB scheme that covers the reactor and line. In fact, a POTT or DCB scheme will not require Zone 2 reach adjustments based on the reactor bypass breaker position if they are set to dependably cover ZX + ZL.

V. Fault Location

This section will focus on impedance-based fault location and how the placement of the VT will affect this, along with looking at the reliability of current-based and voltage-based traveling wave fault location.

A. *Impedance-Based Fault Location*

We will discuss single-ended impedance-based fault location (SEZ) and double-ended impedance-based fault location (DEZ). For this discussion, we focus on transmission line fault location (not faults inside the series reactor). If the transmission line is very short, accurate fault location is not viable.

1) *Bus-Side VT Location*

From the bus-side VT location, impedance-based fault location of any type is not viable as the variable positive-sequence angle and k0 factor needed to accurately measure fault location changes. However, it is possible in some relays to implement relay logic to effectively move the bus-side VT location to the line-side VT location using the impedance of the reactor using (14).

$$\begin{aligned} VA.Line &= VA.Bus - ZX \bullet IA \\ VB.Line &= VB.Bus - ZX \bullet IB \\ VC.Line &= VC.Bus - ZX \bullet IC \end{aligned} \tag{14}$$

In effect, this allows a bus-side VT location to calculate the voltage at the line-side VT location. This calculated line VT measurement is not as accurate as measuring the line VT voltage directly. However, going forward, we treat (14) and a direct measured line-side VT connection as equivalent for simplicity. The SEZ using calculated line voltages is implemented in the relay using custom logic. This can also be calculated in event analysis software.

2) *Line VT Location*

From the line VT location, impedance-based fault location is possible. For bolted faults, or faults in which the remote terminal is open, SEZ will perform well. However, SEZ relies heavily on a homogeneous system for fault location accuracy when fault resistance is present when the remote terminal is closed. In non-homogenous systems, DEZ will perform better than the SEZ for faults with resistance. The SEZ error increases as the system becomes less homogenous.

There are two common implementations of DEZ: DEZC, which relies on remote sequence current, and DEZVC that relies on remote sequence voltage and current. DEZC is implemented in some line current differential relays. This method requires time aligned current samples to create a differential quantity that is used to polarize fault location calculations [17]. This method can provide accurate fault location in the left relay (reactor end) using line VTs, but not bus-side VTs. The right relay will provide accurate fault location for the line regardless of the VT location used on the left relay.

DEZVC fault location requires line VTs at the reactor end of the line. With DEZVC, neither the right nor the left terminal will report an accurate fault location if bus-side VTs are used at the reactor terminal. However, this method does not require time-aligned data [18]. Further, this method only requires one calculation for all unbalanced fault types. Because the computing requirements of DEZVC are low relative to DEZC, DEZVC can be implemented in custom relay logic to provide accurate fault location for line faults [19].

3) *Fault Location Test Results*

The system shown in Fig. 11 was used to test the fault location reported by the relay and the fault location calculated using custom logic. DEZVC and SEZ methods use (14) to calculate the line-side voltage from a bus-side connected VT and are fully implemented in custom relay logic. When the reactor is bypassed, ZX in (14) is set to 0.

A single-line-to-ground fault with a fault resistance of 5 ohms was placed at several points from 0 percent to 100 percent of the line. The tests were repeated with the bypass breaker closed. The following fault location methods were tested:

Algorithms built into the 87L relay:

- DEZC: Double-ended fault location using the remote sequence current.

Fault location calculated using custom relay logic in the 87L relays:

- DEZVC: Double-ended fault location using remote voltage and current.
- Line VT SEZ: Single-ended fault location using the calculated line-side voltages.

The resulting errors in fault location for the left and right relays are shown in Fig. 14 and Fig. 15, respectively. We can make the following general observations based on this data:

- In general, the single-ended methods are less accurate than double-ended methods. Double-ended methods work better for non-homogenous lines with resistance faults.
- The double-ended methods are minimally affected by the bypass breaker position.
- If you must use a single-ended method with the reactor in service, then using the result from the

terminal without the reactor is more accurate. An exception to this generalization would be if the non-reactor end source is very weak (ZR1 > ZX1). In Fig. 15 we can see that Line VT SEZ is more accurate than Line VT SEZ bypass. This is because the reactor reduces the left terminal infeed into the fault resistance making the right terminal more accurate. Conversely, the left terminal becomes less accurate with the reactor in service as the right terminal infeed into the fault resistance is significant and makes the left terminal less accurate.

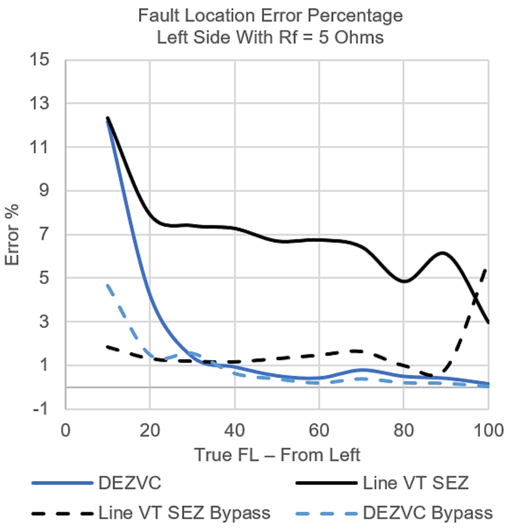

Fig. 14 Fault location error for the left relay (R = 5 ohms)

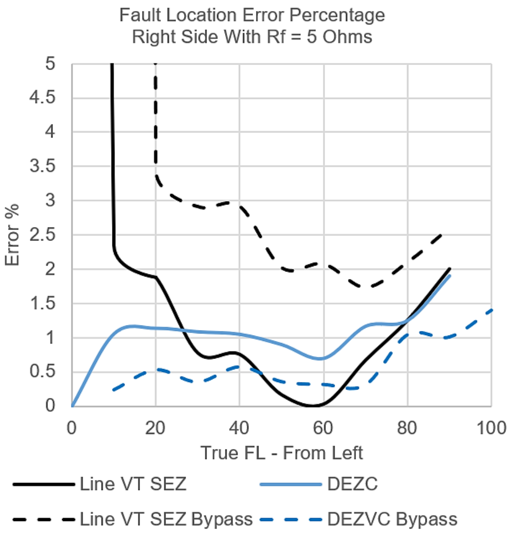

Fig. 15 Fault location error for the right relay (R = 5 ohms)

B. *Traveling Wave Fault Location*

Traveling wave fault location (TWFL) for line faults is appealing because it removes system parameters such as positive- and zero-sequence impedance values, system homogeneity, and secondary current and voltage accuracy as functions of accurate fault location. However, the line reactor has a very high surge impedance relative to the transmission line and makes current-based TWFL a challenge because the reactor makes capturing current-based traveling waves (TWs) at the left terminal unlikely. When a current incident TW arrives at the reactor, nearly all will be reflected to the line. Because the CT measures the summation of the incident and reflected TW, the net result is no measured current TW at the line reactor terminal. Fig. 16(a) shows the incident and reflected current waves. The peak current is equal to the incident voltage (V_I) or reflected voltage (V_R) divided by the characteristic impedance (Z_C). The incident wave enters the polarity side of the CT, and the reflected wave enters the non-polarity side. The sum of the waves on the CT secondary side is equal to zero.

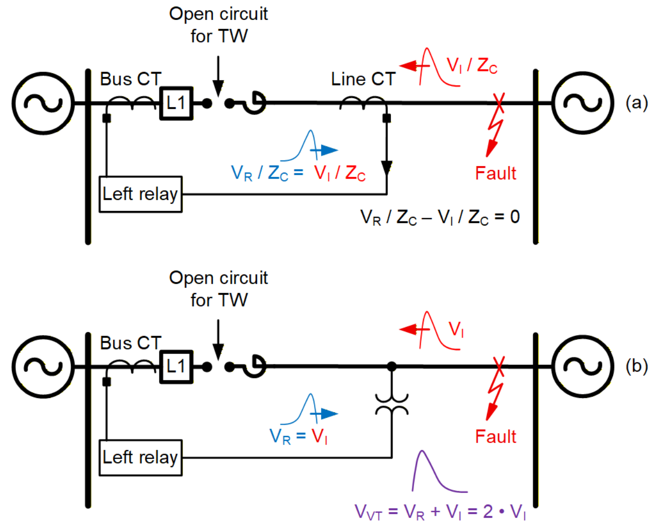

Fig. 16 Equivalent circuit for TW propagation showing the incident (i_I) and reflected (i_R) current wave

While current-based TWFL has low reliability when the reactor is in service, voltage-based TWFL will fare better [20]. When the incident voltage wave arrives at the reactor, nearly all of it will be reflected to the line. Fig. 16(b) shows the voltage waves for the same fault. The voltage measured by the VT (V_{VT}) is the sum of the incident and reflected voltage waves. This leads to a strong voltage traveling wave signal measured at the line-side VTs on the reactor terminal. Bus-side VTs will see no current or voltage TWs.

In general, with line-connected VTs, voltage-based TWFL will work well when the reactor is in service while current-based TWFL will work well when the reactor is bypassed.

VI. OTHER PROTECTION CONSIDERATIONS

In addition to transmission line protection, there are a few protection elements which should be considered for series reactor applications. In this section we briefly cover breaker failure protection and turn-to-turn fault protection.

A. *Breaker Failure*

A recovery voltage appears across the terminals of a circuit breaker after interruption. When current stops flowing, the power system response produces a transient recovery voltage (TRV). After this transient period, the voltage across the breaker is the voltage at nominal frequency. Successful breaker operation occurs when the breaker is able to interrupt the fault current and withstand TRV and power frequency voltages. The characteristic of TRV depends on the circuit being interrupted: capacitive, inductive, or resistive. A TRV study is recommended in applications with series reactors [21]. The TRV and rate-of-rise of TRV for the circuit breaker at the reactor end may exceed the capability of the breaker and can lead to breaker failure [22]. The presence of higher voltages can cause flashovers. In some applications, a capacitor may be added in parallel with the series reactor to control the TRV [23]. It is important to enable breaker failure and flashover protection to quickly detect any issues and isolate the faulted breaker.

Reference [24] shows several methods to provide breaker flashover protection. Reference [25] describes the breaker failure schemes that can be used for different types of bus arrangements. These references can be used for guidance on setting breaker failure and flashover protection.

Transmission line relays that have a high sampling rate (MegaHertz) can be used to measure voltages on both sides of the breaker. These relays can be used to detect breaker flashovers and capture event reports at a high sampling rate that can provide more information about the voltage conditions that led to the flashover [20].

B. *Turn-to-Turn Faults*

In shunt reactors, turn-to-turn fault protection is accomplished with sensitively set zero-sequence and/or negative-sequence overcurrent elements that are supervised by a single directional element that determines if an imbalance from shorted turns is within the reactor (forward) or on the system (reverse). In a series reactor, two directional elements (one on each side of the reactor) with a sensitively set zero-sequence and/or negative-sequence overcurrent element must be used to detect turn-to-turn faults in a comparable manner.

Shunt reactors can have very sensitive turn-to-turn detection with sensitivity estimates that are less than 1 percent of the total turns shorted that can be detected [26]. With series reactors, there are many limiting factors in turn-to-turn fault sensitivity.

- The current transformers must be rated for transmission line load current and transmission line fault current with the reactor bypassed. This may lead to high turns ratios, which desensitize the scheme.
- There is no way to directly measure zero-sequence current practically in a series reactor, so any zero-sequence current must be a residual connection, which means the sensitivity is limited by loadability on the line.
- The line load directly impacts the sensitivity of the scheme. In a shunt reactor, the reactor current is near the full load of the reactor because a phase-to-ground voltage is applied across the reactor. In a series reactor, the voltage drop across the reactor varies based on load flow. Low load flow leads to lower sensitivity.
- Unequal pole closing and opening of the bypass breaker will create a temporary zero-sequence and negative-sequence current that is indistinguishable from a turn-to-turn fault. A time delay for sensitively set zero-sequence and negative-sequence current elements must be implemented to provide security for unequal pole closure.

Additionally, turn-to-turn faults often result from insulation breakdown between the turns. In a shunt reactor, full line-to-ground voltage is applied to the reactor winding exposing it to insulation stress continually as well as any stress to elevated phase-to-ground voltage on the system. In a series reactor, under most conditions, a fraction of the full line-to-ground voltage is applied across the windings. As such, turn-to-turn series reactor faults should be a very rare occurrence.

Appendix E offers more information on turn-to-turn fault detection in series reactors along with contrasts to shunt reactor turn-to-turn fault detection.

VII. CONCLUSION

The following is a summary of key points from this paper:

- 87X is useful for identifying if a fault is in the reactor and using this information for control.
- It is possible to implement 87X in an 87L relay, but this can lead to compromises in the 87L scheme because of the possible need to parallel CT inputs. Implementing 87X in a line protection relay using a POTT or DCB scheme is viable because paralleling CT inputs in these schemes does not sacrifice security as much as in an 87L scheme.
- It is possible to protect the line and reactor with distance elements using a line VT without further study if the reactor impedance is roughly less than two times the line impedance. Using line VTs over bus VTs offers the main advantage of not requiring distance element reach changes when the reactor is bypassed.
- Careful selection of the k0 factor when using ground distance elements can improve security for Zone 1 and dependability for Zone 2 when bus-side VTs are used.
- Impedance-based fault location for line faults must use line-side VT voltages at the reactor terminal. It is possible to take the bus-side VT voltages and shift them to a line VT position mathematically to implement custom impedance-based fault location. However, if the reactor is bypassed, the mathematical line VT calculation must be updated.
- Because of the non-homogeneity of the ZX + ZL zone, doubled-ended impedance-based fault location will perform much better than single-ended impedance-based fault location for resistive faults.
- If single-ended impedance-based fault location must be used, then using results from the terminal without the series reactor will be more accurate.
- When the reactor is in service and line-side VTs are available, voltage-based TWFL is possible.
- Breaker monitoring, including devices with high sampling rates can capture re-strikes or flashovers that can accompany systems with series reactors.

- Dependable turn-to-turn fault protection is difficult to achieve in a series reactor. Further turn-to-turn faults in a series reactor should be very rare.

VIII. Appendix A – Reach Settings

Section IV.A.1 describes how to set the reach for a Zone 1 21PL and 21PB so that it is secure. Equation (15) describes how to set 21PB considering ratio errors, steady voltage errors, and SIR. The reach is adjusted by ZX1 to allow for easy comparison to 21PL.

$$Reach(PU)_{21PB(Adjusted)} = \left[1 - Ratio_{ERR} - V_{ERR} \bullet \left(\frac{ZS1}{ZX1 + ZL1} + 1\right)\right] \bullet (ZX1 + ZL1) - ZX1 \tag{15}$$

Equation (16) simplifies (15).

$$\begin{aligned} Reach_{21PB(Adjusted)} &= ZL1 \bullet (1 - Ratio_{ERROR}) - ZX1 \bullet \\ &Ratio_{ERROR} - V_{ERR} \bullet (ZS1 + ZX1 + ZL1) \end{aligned} \tag{16}$$

Equation (17) describes how to set 21PL considering ratio errors, steady voltage errors, and SIR.

$$Reach(PU)_{21PL} = \left[1 - Ratio_{ERR} - V_{ERR} \bullet \left(\frac{ZS + ZX}{ZL} + 1\right)\right] \bullet ZL \tag{17}$$

Equation (18) simplifies (17).

$$Reach_{21PL} = ZL1 \bullet (1 - Ratio_{ERROR}) - V_{ERR} \bullet (ZS1 + ZX1 + ZL1) \tag{18}$$

We can see that (16) and (18) are similar, but differ by the term ZX1·Ratio$_{ERROR}$. This shows us that 21PB will reach less than 21PL by a factor of ZX1·Ratio$_{ERROR}$.

IX. Appendix B – Reactor Faults

Fig. 17 shows a system diagram. We are solving for the voltages and currents seen at the relay for faults in the reactor.

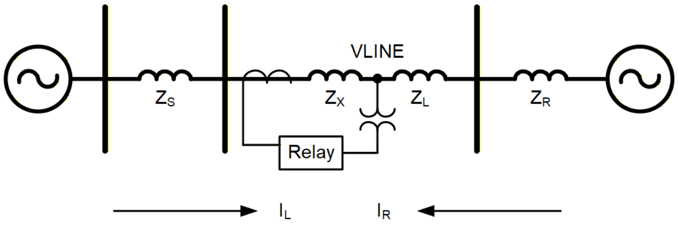

Fig. 17 System diagram

We define the voltage drop from each source to the fault.

$$\begin{aligned} &1 - (ZS + m \bullet ZX) \bullet IL = 0 \\ &1 - (ZR + ZL + (1 - m) \bullet ZX) \bullet IR = 0 \end{aligned} \tag{19}$$

Solve for IL.

$$IL = \frac{1}{ZS + m \bullet ZX} \tag{20}$$

Solve for IR.

$$IR = \frac{1}{ZR + ZL + (1 - m) \bullet ZX} \tag{21}$$

Solve for VLINE.

$$VLINE = 1 - \frac{(ZR + ZL)}{ZR + ZL + (1 - m) \bullet ZX} \tag{22}$$

Solve for Z.

$$Z = \frac{VLINE}{IL} = \left[1 - \frac{(ZR + ZL)}{ZR + ZL + (1 - m) \bullet ZX}\right] \bullet (ZS + m \bullet ZX) \tag{23}$$

X. Appendix C – Determining Maximum Apparent Impedance for Reactor Faults With Line VTs

Referring back to (8), we can reason that if ZR1 is very small (strong remote system), that the apparent impedance seen by 21PL for a reactor fault will increase, which will reduce the ability of Zone 1 to detect reactor faults. This makes sense because a low ZR1 will increase the available voltage at the line VT and therefore increase the apparent impedance. Therefore, we remove ZR1 from (8) as a conservative measure to find the maximum possible apparent impedance for reactor faults while also simplifying the equation. A high ZS1 (weak local system) will also increase the apparent impedance of the reactor. This makes sense because a high ZS1 will decrease the available fault current seen by the 21PL relay and therefore increase the apparent impedance.

Equation (24) provides a check to determine if a distance zone covers the reactor with a dependability margin factor of 1.25. ZX1 and ZS1 are scalar numbers that are in per unit of line impedance.

$$REACH(PU)_{21PL} > \frac{(ZX1 + ZS1 + 2) - \dfrac{2 \bullet (ZX1 + ZS1 + 1)}{\sqrt{1 + ZX1 + ZS1}}}{cos(ang(ZX1) - ang(ZL1))} \tag{24}$$

Although this formula seems formidable, this can be further simplified by accumulating results for various values of ZX1, ZS1, and angle (ZL1) under the assumption that angle(ZX1) is 90 degrees and 21PL$_{REACH(PU)}$ = 0.8. This assumption is specifically for Zone 1 distance elements, and the final result is shown in (10).

XI. Appendix D – k0 Factor

The k0 factor for the compensated line at a specific reach point on the line can be defined as shown in (25).

$$k0L_{21GB} = \left[\frac{\left(ZX0 + ZL0 \bullet Reach(PU)_{21PB(Adjusted)}\right) - \left(ZX1 + ZL1 \bullet Reach(PU)_{21PB(Adjusted)}\right)}{3 \bullet \left(ZX1 + ZL1 \bullet Reach(PU)_{21PB(Adjusted)}\right)}\right] \tag{25}$$

When ZX1 = ZX0, this can be simplified as shown in (26).

$$k0L_{21GB} = \frac{ZL0 \bullet Reach(PU)_{21PB(Adjusted)} - ZL1 \bullet Reach(PU)_{21(Adjusted)}}{3 \bullet \left(ZL1 \bullet Reach(PU)_{21PB(Adjusted)} + ZX1\right)} \tag{26}$$

XII. Appendix E – Turn-To-Turn Faults

Fig. 18(c) shows the protection one-line diagram for shunt reactor turn-to-turn fault detection. The underlying assumption is that turn faults will not occur evenly in all three phases, so a sensitively set zero-sequence or negative-sequence overcurrent element can determine if there is an imbalance possibly related to a turn-to-turn fault. A directional element narrows down the location of the imbalance by identifying forward for reactor turn faults and reverse for system imbalances.

Fig. 18(a) and Fig. 18(b) show a principle that is roughly equivalent except for the series reactors. This requires the use of two directional elements and VTs on each side of the reactor. Fig. 18(a) shows a scheme that does not require communication and can be implemented in a single relay. However, a custom directional element must be created in the relay logic in addition to the built-in directional element to provide protection. Fig. 18(b) shows a more traditional line protection scheme in which the left and right terminal have a sensitive directional element to detect turn faults.

We note that a turn-to-turn fault detection is similar to open phase detection. These are series faults, and VT location in relationship to the series fault is directly related to how directionality is determined. This is in contrast with shunt faults, in which the CT location in relationship to the shunt fault is directly related to how directionality is determined. A downside to the local turn-to-turn fault detection method shown in Fig. 18(a) is that line VTs alone cannot be used to detect reactor turn-to-turn faults. There must be a VT on each side of the reactor to determine the location of the sequence imbalance introduced by turn-to-turn faults. This scheme will identify if the reactor or the line is faulted, which can be useful if 87X is unavailable.

In the communications-based scheme, only a bus-side VT is needed at the reactor end. The only minimal downside to this scheme, other than the communication requirement, is that operation of the sensitive directional elements is an ambiguous indication of a fault on the line or a fault in the reactor.

While turn-to-turn protection for a series reactor can be very challenging, we illustrate a simulation using the local turn-to-turn fault detection scheme in which Phase A impedance is 10 percent smaller than Phase B and Phase C impedance as an approximation of a turn-to-turn fault. In the rest of this appendix, we focus on 32V, but 32Q can be used in the same manner. As seen in Fig. 19, the I0 current leads 3V0.Bus, which indicates a forward fault from the perspective of a 32V connected to bus VTs. The I0 current lags 3V0.Line, which indicates a reverse fault from the perspective of a 32V connected to line VTs. We also show that the apparent impedance of Phase A of the reactor has dropped from 1.6 ohms to 1.44 ohms. This is calculated by subtracting the VA voltage on the bus and line and dividing by the IA current.

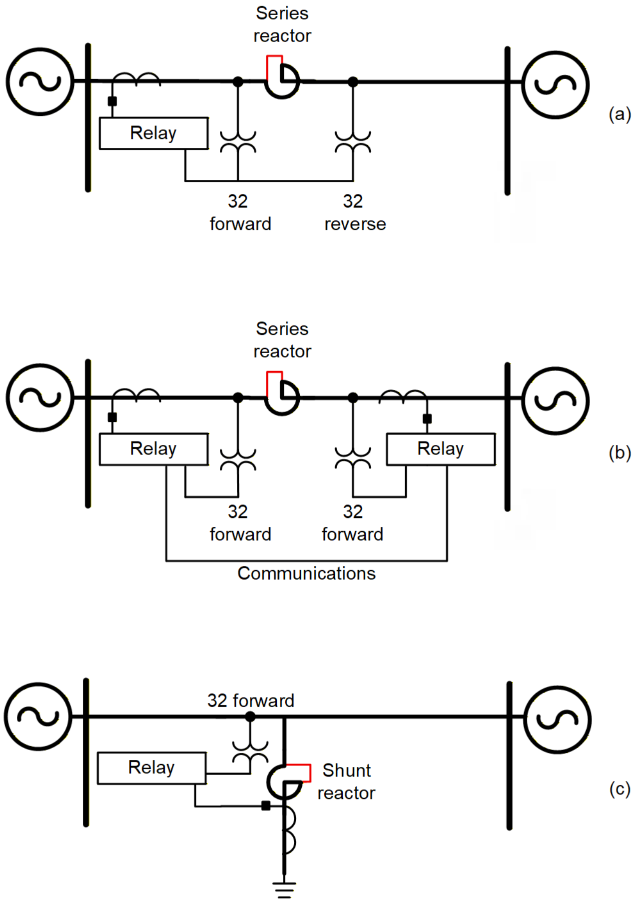

Fig. 18 Series reactor versus shunt reactor

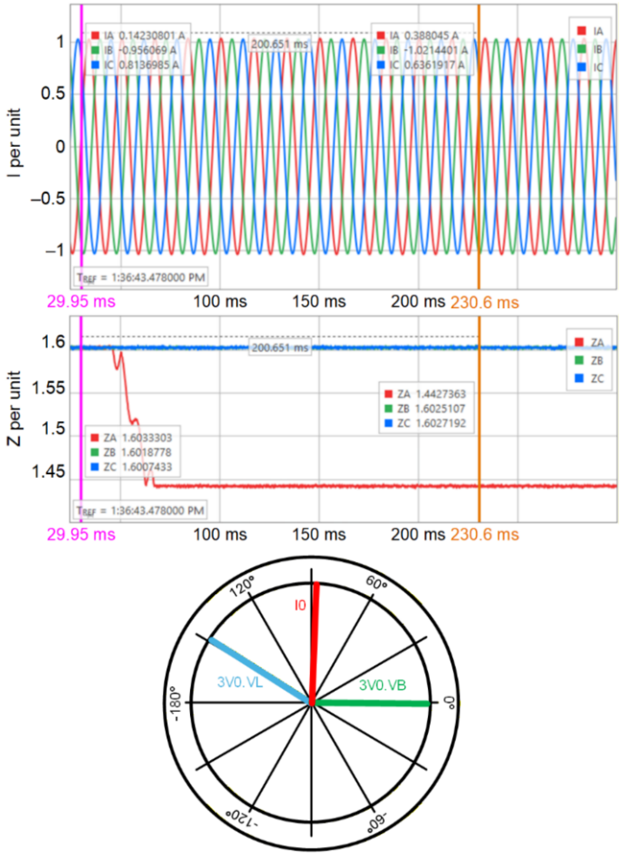

Fig. 19 10 percent turns shorted in series reactor

To make the 32V as dependable as possible, the bus-side VT 32V is set with biased thresholds (AUTO4 from [13] to allow forward declaration operation even if no 3V0 is present. The line VT 32V is set with biased threshold (AUTO3) to allow reverse declaration of "no 3V0 is present." For the relay to operate on turn-to-turn faults, 32VF-bus and 32VR-line must assert AND enough zero-sequence current must be present for an operation to occur. Further, a short time delay of three cycles is recommended to add security for bypass breaker operations.

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XIV. BIOGRAPHIES

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