Review of SIR Calculations for Distance Protection and Considerations for Inverter-Based Resources

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***Abstract*—Source-to-line impedance ratio (SIR) is a parameter used in the application of distance protection. IEEE Std C37.113-2015 (Line Protection Guide) presents a method to calculate SIR for three-phase faults and single-line-to-ground faults. This method has been incorporated into short-circuit programs and is used by practitioners. However, the method uses assumptions that produce erroneous results in systems with zero-sequence mutual coupling and in systems with inverter-based resources. This paper reviews the evolution of SIR calculations (methods) and advocates the use of newer and simpler SIR calculations that remain accurate for all distance protection applications.**

***Index Terms*—Ground, IBR, impedance, mutual coupling, negative-sequence, phase, ratio, real-code model, security, source, synchronous generator, system, WTG, zero-sequence, Zone 1.**

I. Introduction

The source-to-line impedance ratio (SIR) is an important parameter used to determine the type of line protection that can be applied as well as the protection settings [1]. Short-circuit programs are now commonly used by engineers and provide automated methods to calculate SIR for a particular line terminal [2], [3]. When the SIR is low, the voltage measured by the relay (the relay voltage) is high for remote line faults. Measurement errors are small in comparison to the relay voltage and an underreaching distance Zone 1 element can be securely applied. On the other hand, when the SIR is high, measurement errors can dominate the relay voltage and the reach of distance elements may need to be reduced or the elements may need to be disabled [4], [5], [6]. Consequently, greater reliance on the communications-assisted protection—pilot schemes or line current differential—is required.

The increased penetration of inverter-based resources (IBRs) plays a role in increasing SIR. IBR models in short-circuit programs are improving through continued collaboration between IBR manufacturers (OEMs) and short-circuit program manufacturers to refine the models [7]. On the other hand, the older SIR calculations (methods) [1], [8] implemented in several short-circuit programs have inaccuracies in systems with IBRs and in systems with zero-sequence mutual coupling.

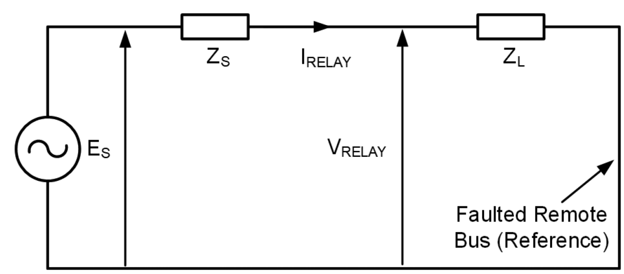

Fig. 1. Equivalent circuit used to calculate SIR.

This paper presents a historical review of SIR calculations and their evolution for distance protection (Section II). The most recent SIR calculations of [4] are simple. However, considering the extensive use of the older and more complex SIR calculations in existing engineering tools, including short-circuit programs, simplicity may not be sufficient justification to change the way SIR is calculated. This paper points out the significant accuracy improvements of the newer SIR calculations in systems with zero-sequence mutual coupling (Section III) and in systems with IBRs (Section IV). As these applications become more common, the use of the newer and more accurate SIR calculations becomes more important in evaluating protection applications and improving reliability.

II. Evolution of SIR Calculations

In this section, we review the history and evolution of SIR calculations.

A. The Early Days With One SIR (Until Year 2000)

The basic concept of SIR and its impact on distance protection has been well understood by engineers. The equivalent voltage divider circuit of Fig. 1 is used to calculate SIR as the ratio of the source impedance (Z_S) to the line impedance (Z_L). A bolted fault at the remote bus is used to obtain the relay voltage (V_{RELAY}) because it is the first point of over- or underreach for a distance zone, and it also prevents the SIR from changing when a zone reach is adjusted. Fig. 2 shows how V_{RELAY} varies with SIR (note the logarithmic scale). When V_{RELAY} is too small, a measurement error that is a fixed percentage of nominal (and

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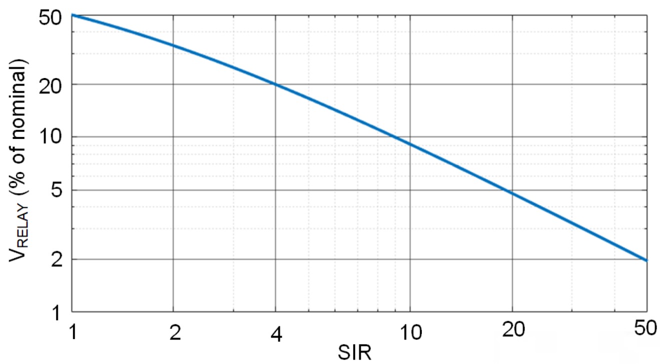

Fig. 2. Relay voltage versus SIR for a bolted fault on the remote bus.

not a percentage of V_{RELAY} [6]) can cause a Zone 1 distance element to overreach.

Warrington's 1968 book [9] discusses this accuracy limit of distance relays as a percentage of normal voltage or a "Z_S/Z_L" ratio for electromechanical mho and reactance relays. Similarly, a 1968 paper from a relay designer [10] presented the accuracy and speed of their transistor distance relay as a function of SIR. The discussions all related to one SIR, consistent with Fig. 1, which is a simplified one-line representation of the three-phase power system.

Despite the use of one SIR, it was recognized that the SIR for phase faults and ground faults are different, as evidenced by the use of (1) and (2) in [11] to calculate the line-to-line relay voltage for phase faults (V_{RELAY_LL}) and line-to-ground relay voltage for ground faults (V_{RELAY_LG}), respectively. These equations are derived from the voltage divider circuit of Fig. 1. The SIR values in these equations are included as impedance ratio terms in the denominator. Using the SIR to calculate the relay voltage helps relate it directly to a voltage measurement error.

The difference in the SIR for phase and ground faults becomes apparent when inspecting (1) and (2) and considering that the ratio of the zero-sequence to positive-sequence impedance of the source, due to zero-sequence paths presented by network transformers, tends to be lower than that of the line. Consequently, the SIR for single-line-to-ground faults is often lower than that of three-phase faults, which translates to a higher relay voltage for ground faults compared to phase faults.

$$V_{RELAY\_LL} = \frac{E_{S\_LL}}{(Z1_S/Z1_L)+1} \tag{1}$$

$$V_{RELAY\_LG} = \frac{E_{S\_LN}}{(Z_S/Z_L)+1} \tag{2}$$

where:

E_{S_LL} is the line-to-line source voltage
E_{S_LN} is the line-to-neutral source voltage
$Z1_S$ is the positive-sequence source impedance
$Z1_L$ is the positive-sequence line impedance
$Z0_S$ is the zero-sequence source impedance
$Z0_L$ is the zero-sequence line impedance
Z_S is $2 \bullet Z1_S + Z0_S$
Z_L is $2 \bullet Z1_L + Z0_L$

Until the 1990s, with widespread use of electromechanical relays, it was common to apply phase distance relays for phase fault protection and ground overcurrent relays for ground fault protection. The cost of one overcurrent relay in the residual circuit was about one-tenth the cost of the three equivalent ground distance relays and their auxiliaries [9]. Therefore, because it was distance protection that relied on voltage measurement accuracy, the main impact of SIR was on the phase element, and the separate SIR in (2) for ground faults was not needed.

In the 1990s, short-circuit programs were also just starting to see use and it was challenging to calculate a separate SIR for ground faults. Therefore, the term SIR was synonymous with the SIR for phase faults. The initial version (1999) of IEEE Std C37.113 (Line Protection Guide) used this one SIR to classify the relay voltage, translating to an electrical line length, to discuss the types of protection schemes that were typically applied based on this classification [12].

B. Developments Related to IEEE Std C37.113-2015 (∼2000 to 2020)

With microprocessor-based relays gaining popularity, ground distance protection became more accessible and more widely applied. At the same time, short-circuit programs started gaining popularity [13], making it easier to obtain fault currents and voltages to evaluate settings for a specific system. Consequently, during the revision of the Line Protection Guide leading up to 2015 [1], the need for separate phase and ground SIRs for the application of phase distance and ground distance protection, respectively, became evident.

At the time, there was no clear guidance on how to practically calculate the source impedance (and thus SIR) for a meshed system that deviated from the simple representation of Fig. 1 and (1) and (2). A common approach to calculating SIR sought a Thevenin equivalent source impedance value by using methods that placed a fault at the local terminal [8]. This does not represent the case that the relay experiences for a remote bus fault with the other network elements in service. The key improvement presented in [8] was to leave the network configuration intact and place a bolted fault at the remote bus. The working group revising the Line Protection Guide leveraged this improvement and included (3) and (4) to calculate the SIR for three-phase faults (SIR_{3PH}) and (5) and (6) to calculate the SIR for single-line-to-ground faults (SIR_{SLG}). Another improvement offered by [8] was that (3) to (6) used quantities made available by short-circuit programs, unlike (1) and (2) that used the ambiguously obtained source impedance data to calculate the relay voltage.

$$ZS_{3PH} = \frac{V_{DROP\_SRC}}{I_{RELAY}} = \frac{V_{BASE\_LN} - V_{RELAY}}{I_{RELAY}} \tag{3}$$

$$SIR_{3PH} = \frac{ZS_{3PH}}{Z1_L} \tag{4}$$

where:

ZS_{3PH} is the source impedance for phase loops
V_{BASE_LN} is the system line-to-neutral base voltage
V_{RELAY} is the phase-to-ground voltage at the relay

SOURCE IMPEDANCE RATIOS FOR PHASE FAULTS:

OUTAGE	Vdrop (V)	Irelay (A)	Vdrop/Irelay (ohm)	SIR
None	69121.9	1242.41	55.6353	5.865
N01	44367.4	3987.25	11.1273	1.173
N02	75668.1	761.109	99.4181	10.48
N03	69121.9	1242.41	55.6353	5.865

SOURCE IMPEDANCE RATIOS FOR GROUND FAULTS:

OUTAGE	Vdrop (V)	Irelay (A)	Vdrop/Irelay (ohm)	SIR
None	61650.8	2212.89	27.8599	2.937
N01	30852.4	5536.57	5.57248	0.587
N02	70405.7	1648.08	42.7198	4.503
N03	63995	2052.31	31.1819	3.287

LIST OF OUTAGED BRANCHES BEHIND RELAY LOCATION:

N01	Line	0 BUS_LOCAL 138.kV - 0 BUS_REMOTE 138.kV 2L
N02	Line	0 BUS_LOCAL 138.kV - 0 BUS_SRC0 138.kV 1L
N03	2W Xfmr	0 BUS_LOCAL 138.kV - 0 BUS_MV 13.8kV 1T

Fig. 3. SIR calculation from a short-circuit program considering contingencies.

I_{RELAY} is the phase current at the relay
$Z1_L$ is the positive-sequence line impedance

$$ZS_{SLG} = \frac{V_{DROP\_SRC}}{I_{RELAY}} = \frac{V_{BASE\_LN} - V_{RELAY}}{I_{RELAY} + k_0 \bullet 3I0_{RELAY}} \quad (5)$$

$$SIR_{SLG} = \frac{ZS_{SLG}}{Z1_L} \quad (6)$$

where:
ZS_{SLG} is the source impedance for ground loops
$3I0_{RELAY}$ is the zero-sequence current at the relay
$Z0_L$ is the zero-sequence line impedance
k_0 is the zero-sequence compensation factor, calculated as $\frac{1}{3} \bullet (\frac{Z0_L}{Z1_L} - 1)$

The calculations of (3) to (6) were subsequently automated in short-circuit programs so an engineer could obtain a report like Fig. 3 [2]. Short-circuit programs typically do not use the system base voltage of (3) and (5) directly because a system may have multiple sources with different operating voltages. Instead, they solve for and use a pre-fault voltage reference that represents the equivalent source voltage [2], [3]. As shown in Fig. 3, short-circuit programs can also automatically consider contingencies such as a line or a transformer outage. Thus, the use of SIR to determine suitability of distance elements for line protection became simple and widespread.

C. Recent Improvements in SIR Calculations (Since 2020)

With increasing penetration of IBRs, the topic of SIR and considerations for distance protection gained more attention. Reference [4] presents improved and simplified SIR calculations—the equivalent equations are shown for the phase SIR (SIR_P) for the phase distance element and ground SIR (SIR_G) for the ground distance element in (7) and (8), respectively. These equations are obtained by rearranging (1) and (2) to solve for SIR. The simplification in (7) and (8) uses just the relay voltage, as made available by a short-circuit program, to calculate SIR. They do not need the additional relay currents and line impedances required in (3) to (6).

$$SIR_P = \frac{V_{BASE}}{V_{RELAY\_LL}} - 1 \quad (7)$$

$$SIR_G = \frac{V_{BASE}}{\sqrt{3} \bullet V_{RELAY\_LG}} - 1 \quad (8)$$

where:
V_{RELAY_LL} is the line-to-line voltage magnitude at the relay for a bolted line-to-line (LL) fault on the remote bus
V_{RELAY_LG} is the line-to-ground voltage magnitude at the relay for a bolted single-line-to-ground (SLG) fault on the remote bus
V_{BASE} is the system line-to-line base voltage

A key observation in [4] is that the voltage error for a distance element directly impacts the operating signal "IZ – V", where I is the loop current, Z is the reach, and V is the loop voltage. The operating signal applies generally to all distance elements, including mho and quadrilateral. Using the loop voltages V_{RELAY_LG} for the ground distance element (Loops AG, BG, and CG) and V_{RELAY_LL} for the phase distance element (Loops AB, BC, CA) is a very direct representation of the distance element. The SIR and related measurement error also apply directly to the loop voltages.

The loop voltage is not strictly consistent with the ratio of the source impedance to the line impedance, which can be observed in nonhomogeneous systems [4]. Consider a $Z1_S$ of 4 pu and a $Z1_L$ of 1 pu. In a homogeneous system, with the angle of $Z1_S$ equal to the angle of $Z1_L$, V_{RELAY} calculated using (1) is 0.200 pu. In a nonhomogeneous system with the angle of $Z1_S$ leading (or lagging) the angle of $Z1_L$ by 20 degrees, V_{RELAY} calculated by (1) increases to 0.202 pu. The V_{RELAY} calculated using (1) and (2) in nonhomogeneous systems is always higher, which translates to a lower SIR calculations using (7) and (8). In contrast, because (3) and (5) calculate the voltage drop across the source impedance, the related SIR calculations in (4) and (6) ignore system nonhomogeneity. The differences in the calculated SIR value are insignificant in most systems. However, they illustrate that in the early days [11] and more recently [4], the focus of SIR was on the relay voltage. On the other hand, the developments related to IEEE Std C37.113-2015 included a literal ratio of the source impedance to the line impedance.

The improvements presented in [4] were recognized by the first author of [8], who wrote another paper [5] agreeing to the improvements. However, the consensus was that the improvements in (7) and (8) were simplifications but not necessarily an improvement in the technical accuracy relative to (3) through (6). And while it is true that the two sets of equations provide the same result in most cases, they may not remain equal in systems with mutual coupling or in systems near IBRs.

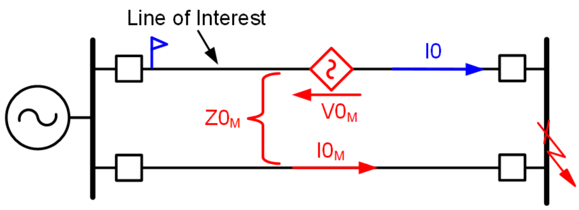

Fig. 4. Additional voltage due to zero-sequence mutual coupling.

SOURCE IMPEDANCE RATIOS FOR GROUND FAULTS:				
OUTAGE	Vdrop (V)	Irelay (A)	Vdrop/Irelay (ohm)	SIR
None	61861.9	1290.41	47.9397	5.054

Fig. 5. SIR calculation from a short-circuit program for a mutually coupled line.

III. Zero-Sequence Mutual Coupling Considerations

A bolted SLG fault at the remote bus of a transmission line results in the relay voltage shown by (9).

$$V_{RELAY\_LG} = Z1_L \bullet (I_{RELAY} + k_0 \bullet 3I0_{RELAY}) \quad (9)$$

Mutual coupling adds a voltage term (V_{0M}) to (9) [14], as shown in (10) and illustrated by the ac current-controlled voltage source in Fig. 4.

$$V_{RELAY\_LG\_MC} = Z1_L \bullet (I_{RELAY} + k_0 \bullet 3I0_{RELAY}) + V0_M \quad (10)$$

$$V0_M = Z0_M I0_M \quad (11)$$

where:
$Z0_M$ is the zero-sequence mutual coupling impedance
$I0_M$ is the zero-sequence current in the coupled line

Mutual coupling also introduces an error in the SIR_{SLG} calculation of (5) and (6) because the denominator of (5) ignores the V_{0M} term of (10), just like (9). The issue is similar to how a ground distance element can under- or overreach when protecting a mutually coupled line. On the other hand, the numerator of (5) uses V_{RELAY}, which includes the effect of mutual coupling when obtained from a short-circuit program. This introduces an inconsistency between the numerator and denominator of (5) in mutually coupled lines.

If we replace the denominator of (5) with V_{RELAY_LG} calculated by a short-circuit program, we get the equivalent of the SIR_G calculated in (8)—this equation includes the effect of mutual coupling and accurately represents the loop voltage available to a ground distance element. The loop voltage in mutually coupled lines does not accurately represent the distance to the fault—this issue is typically addressed separately by adjusting the distance element reach.

An example of the errors introduced for a mutually coupled 138 kV line is illustrated using the output of a short-circuit program in Fig. 5. The lines have a $Z0_M$-to-$Z0_L$ ratio of 67 percent and are fed by the same source (like Fig. 4). Both lines carry equal current for a fault at the remote bus. The program uses (5) and returns an SIR_G of 5.054. If we use V_{RELAY} and apply (8), we get an SIR_G of 3.463. In this example, the short-circuit program overestimates SIR_G by nearly 50 percent. A 50 percent increase in an SIR estimate might inadvertently cause an engineer to choose to not apply a ground distance element. If the parallel line current is higher (in a different line configuration), the SIR_G estimate could be even greater. On the other hand, mutual coupling can also cause an underestimation of SIR by using (5) for scenarios that cause a distance element overreach [14], which might inadvertently cause a security issue. Using the SIR_G calculation of (8) can mitigate these issues.

IV. Considerations for Synchronous Generators and IBRs

The discussions so far rely on the assumption that the source is an ideal voltage with impedances $Z1_S$ and $Z0_S$. Both synchronous generators and IBRs deviate from the behavior of an ideal source, including presenting a different negative-sequence impedance ($Z2_S$) compared to $Z1_S$. When $Z2_S$ is different from $Z1_S$, the SIR_P for a line-to-line fault becomes different from that of a three-phase fault. This section discusses this and other considerations that can significantly impact the calculation of SIR_P of lines near sources.

A. SIR Calculations in Synchronous Generator Systems

This section discusses considerations for SIR calculations for lines near synchronous generators based on data from nearly 20 generator data sheets. The subtransient reactance of a synchronous generator is typically used as its $Z1_S$ when calculating SIR. A generator's unsaturated reactance values (e.g., the unsaturated subtransient) are higher than its corresponding saturated reactance values and may be used to obtain a more conservative estimate of SIR.

1) Salient-Pole Generators: Salient-pole generators typically have a quadrature-axis subtransient reactance that is higher than the direct-axis subtransient reactance—sometimes more than 50 percent and in rare cases, more than 100 percent.

Short-circuit programs usually do not have separate input entries to include both direct- and quadrature-axis reactance values. If using the direct-axis reactance, the calculated SIR is lower than the true SIR value. To improve the accuracy of both phase and ground SIR calculations, we recommend using the average of the direct- and quadrature-axis reactance values. For cylindrical-rotor generators, the direct- and quadrature-axis reactance values are equal, so this recommendation may be applied generally when modeling any synchronous generator.

2) Unbalanced Faults: For unbalanced faults, synchronous generators have a $Z2_S$, which can be higher or lower than their subtransient reactance—sometimes more than 20 percent different than the average of the direct- and quadrature-axis reactance values. This can make the SIR_{3PH} calculation of (3) and (4) higher or lower than the SIR_P calculated in (7) for an LL fault. The SIR_{3PH} calculation of (3) and (4) uses the phase-to-ground voltage measured by the relay and, therefore, cannot be directly applied for LL faults. Consequently, to obtain a conservative estimate of SIR_P, we suggest using (7) for LL and three-phase faults separately and using the greater of the two resultant values. The difference between the $Z1_S$ and $Z2_S$ can also impact SIR_G, but the effect is much less and is already accounted for in V_{RELAY_LG} obtained from short-circuit programs for SLG faults.

3) Time-Varying Reactance Values: Synchronous generators have time-varying impedances—initially subtransient, later transient, and eventually synchronous. For the purpose of SIR calculations, short-circuit programs typically use the subtransient reactance, which is the smallest. This is a reasonable approximation when using the underreaching Zone 1 element that operates without any intentional delay.

Time-delayed step-distance zones are typically not as impacted by high SIR as the fast-tripping Zone 1 element. Transient measurement errors significantly impact a Zone 1 element [6] but not time-delayed step-distance zones. Therefore, it is not necessary to modify and add complexity to SIR calculation practices. However, it may be a consideration to use the transient or synchronous reactance values when determining coordination margins for step-distance zones near small generating plants that could result in a high SIR. For example, it can be confirmed—by considering the different sources of errors in a high SIR application [6]—that a step-distance Zone 2 has an adequate dependability margin to protect the entire line and an adequate security margin to not overreach the Zone 1 in an adjacent short line. Infeed effect tends to increase the relay voltage [1], so the security margin for coordination does not need to be as high as the dependability margin.

B. SIR Calculations in Systems With IBRs

1) Limited Negative-Sequence Current Injection Capability: The fault response of an IBR is primarily impacted by its control. IBRs might not yet be standardized and the negative-sequence current (I2) they inject can be very small [15] and depends on the IBR type and the IBR manufacturer (OEM) [16]. The associated $Z2_S$ of an IBR can be very large and is sometimes represented as an open circuit [15].

Figs. 6 and 7 illustrate the 230 kV system fault response of Type 4 Wind Turbine Generators, simulated using real-code models provided by two OEMs [16]. The IBR terminal currents and voltages are shown for a bolted LL fault at the remote bus of a 40-mile line. For both OEMs, the IBR controls significantly reduce I2 and the fault currents, after a transient period, look like a balanced three-phase condition.

To understand how the reduced I2 from an IBR affects V_{RELAY_LL} and SIR_P, consider the sequence network for a bolted line-to-line fault at the remote bus in Fig. 8. A voltage source is used in Fig. 8 to simplify the analysis. This simplification is useful when analyzing certain IBR and synchronous generator applications. Although certain control strategies can cause an IBR to behave more like a current source instead of a voltage source, a Norton-equivalent current source can be converted to a Thevenin-equivalent voltage source at a particular operating point [17].

From Fig. 8, the sequence voltages measured by the relay are:

$$V1_{RELAY} = V1_S - I1_{RELAY} \bullet Z1_S \tag{12}$$

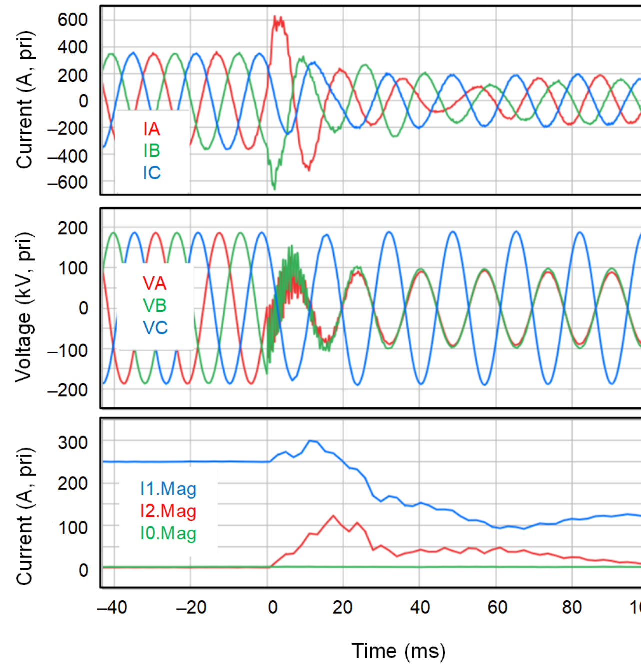

Fig. 6. OEM1 IBR response for a bolted AB fault at the remote bus.

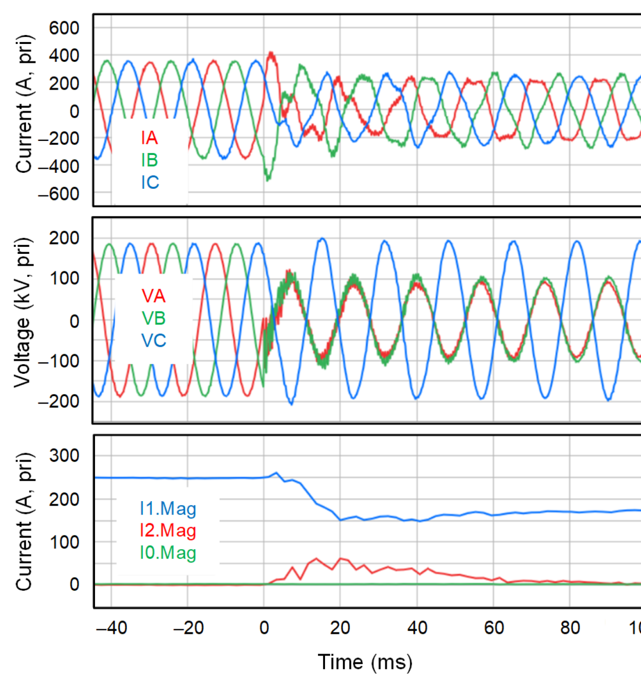

Fig. 7. OEM2 IBR response for a bolted AB fault at the remote bus.

$$V2_{RELAY} = -I2_{RELAY} \bullet Z2_S \tag{13}$$

From the sequence voltages, we calculate the magnitude (the | | operator) of the line-to-line voltage as:

$$V_{RELAY\_LL} = \left| -\sqrt{3}j \bullet (V1_{RELAY} - V2_{RELAY}) \right| \tag{14}$$

$$V_{RELAY\_LL} = \sqrt{3} \bullet |V1_{RELAY} - V2_{RELAY}| \tag{15}$$

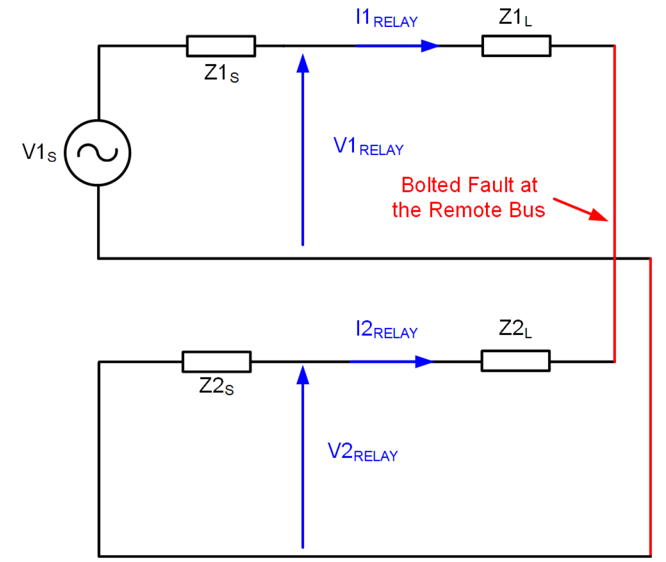

Fig. 8. Sequence network for a bolted line-to-line fault at the remote bus.

Substituting (12) and (13) to (15) and recognizing from Fig. 8 that $I2_{\mathrm{RELAY}} = -I1_{\mathrm{RELAY}}$, we get:

$$V_{RELAY\_LL} = \sqrt{3} \bullet |V1_S - I1_{RELAY} \bullet (Z1_S + Z2_S)| \tag{16}$$

We calculate $I1_{\mathrm{RELAY}}$ assuming $Z1_L = Z2_L$ as:

$$I1_{RELAY} = \frac{V1_S}{(Z1_S + Z2_S + 2 \bullet Z1_L)} \tag{17}$$

Substituting (17) to (16), we get:

$$V_{RELAY\_LL} = \sqrt{3} \bullet \left| V1_S - V1_S \bullet \frac{Z1_S + Z2_S}{Z1_S + Z2_S + 2 \bullet Z1_L} \right| \tag{18}$$

Simplifying (18), we get:

$$V_{RELAY\_LL} = \sqrt{3} \bullet V1_S \bullet \left| \frac{2 \bullet Z_{1L}}{Z_{1S} + Z_{2S} + 2 \bullet Z_{1L}} \right| \tag{19}$$

The sequence network for a three-phase fault involves only the positive-sequence network of Fig. 8, and the line-to-line voltage measured by the relay is:

$$V_{RELAY\_LL\ (3P\ FAULT)} = \sqrt{3} \bullet V1_S \bullet \left| \frac{Z1_L}{Z1_S + Z1_L} \right| \tag{20}$$

To compare $V_{\mathrm{RELAY\_LL}}$ for the LL fault and three-phase fault, we divide (19) by (20):

$$\frac{V_{RELAY\_LL\ (LL\ FAULT)}}{V_{RELAY\_LL\ (3P\ FAULT)}} = \frac{Z1_S + Z1_L}{\left(\frac{Z1_S + Z2_S}{2}\right) + Z1_L} \tag{21}$$

For ease of understanding, we define the impedance ratio of $Z2_S$-to-$Z1_S$ as $k2_S$ and represent (21) as:

$$\frac{V_{RELAY\_LL\ (LL\ FAULT)}}{V_{RELAY\_LL\ (3P\ FAULT)}} = \frac{Z1_S + Z1_L}{Z1_S \bullet \left(\frac{1 + k2_S}{2}\right) + Z1_L} \tag{22}$$

If $Z2_S$ equals $Z1_S$, $k2_S$ equals 1, (22) evaluates to 1, and there is no difference in the relay voltage and SIR for an LL fault versus a three-phase fault (as we expect). On the other hand, if $k2_S$ is large—as in the case of an IBR that limits I2—the difference in the relay voltage and SIR can be extremely high. The effect is further amplified in high SIR systems (large $Z1_S$), as in the case of IBRs that have a rated phase current limit.

For an example system with $Z1_S$ that is 10 times $Z1_L$ and $Z2_S$ that is 10 times $Z1_S$ (i.e., $k2_S = 10$), the relay voltage calculated by (22) for a line-to-line fault is less than 20 percent of that for a three-phase fault. The SIR_P for a three-phase fault for such a system is 10, but the SIR_P for a line-to-line fault exceeds 50. These extreme differences in the relay voltage and SIR_P between line-to-line faults and three-phase faults highlight the importance of considering line-to-line faults when calculating SIR_P.

2) Standardized IBRs: IBRs may also be standardized to provide I2 according to performance requirements [18], [19]. However, the I2 they inject may differ significantly from the positive-sequence current (I1) because there can be many combinations that satisfy the requirements from the standards [20]. With non-standardized IBRs that are fully converter interfaced, as discussed, usually the SIR_P for LL faults is significantly higher than that for three-phase faults. With standardized IBRs that intend to maximize grid support during low-voltage ride-through while remaining within their rated phase current limits [20], the SIR_P for LL faults can be lower, easing application concerns for distance protection. The inverter control setpoints can also impact SIR_P. As with synchronous generators, a conservative approach is to use (7) for both LL and three-phase faults and use the greater of the two resulting values.

To accurately represent the IBR in a short-circuit program, it is best to use data from an IBR OEM, such as a dynamic-link library (DLL) model for a short-circuit program [2]. There have been efforts to model the IBR response in a few short-circuit programs [7]. The accuracy of IBR models in short-circuit programs continues to improve. For practical reasons, however, it may not be possible to obtain an accurate IBR model from the OEM and include it as part of the fault study. If generic IBR models are used, then a conservative estimate of the SIR can be obtained by limiting the I2 capability—for example, using a negative-sequence slope setting of zero, as shown in Fig. 9 [2], indicating no injection of I2 in the presence of a negative-sequence voltage.

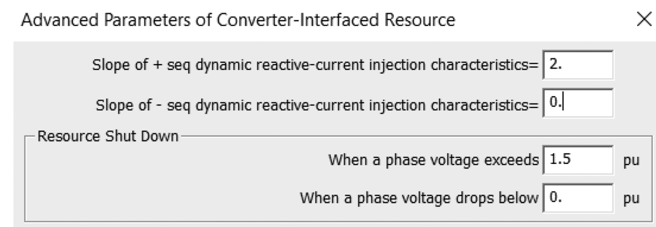

Fig. 9. Example short-circuit program parameter to control injected I2.

3) Line Length and Application Considerations for High SIR: This section presents a perspective on the line lengths required for IBR applications so as to not have significant concerns about phase distance element applications. If we refer back to Figs. 6 and 7, we notice that the faulted-phase voltage traces are practically on top of each other even though the fault is at the remote bus. This is a characteristic of a system with an extremely high SIR_P. The line-to-line voltage during the fault is about 7 kV (or 3 percent of V_{BASE}). Using (7), this is an SIR_P of 32 for the 230 kV 40-mile line. Considering $Z1_L$ of 32 ohms primary, the effective source impedance of the 100 MVA IBR plant is about 1.9 pu. IBRs typically limit the fault current to approximately 1.1 to 1.3 pu [7], which translates to an impedance greater than 0.75 pu. The additional impedance to 1.9 pu (including the 0.75 pu) corresponds to the limited I2 capability, the impedance of the collector system, and the step-up transformers.

The source impedance of a synchronous generator, in contrast, is in the range of 0.10 to 0.65 pu. Including a generator step-up transformer with an impedance of 0.05 to 0.20 pu, a synchronous generating plant may present an impedance of about 0.15 to 0.85 pu. An IBR plant impedance, even if it provides significant I2, would generally present an impedance more than twice that of a synchronous generating plant. When it does not produce significant I2, using our example with an IBR plant impedance of 1.9 pu, the effective source impedance of an IBR plant can be more than thrice that of a synchronous generating plant.

The minimum line length permissible for a given maximum SIR value (SIR_{MAX}) in a distance element application can be calculated by using (23).

$$Line\ Length > \frac{{V_{BASE}}^2}{S_{IBR}} \bullet \frac{Z_{PLANT\_PU}}{SIR_{MAX} \bullet Z1_{L\_PL}} \tag{23}$$

where:

V_{BASE}	is the system line-to-line base voltage
S_{IBR}	is the rated MVA of the IBR
Z_{PLANT_PU}	is the per-unit plant impedance (e.g., 1 to 2 pu)
$Z1_{L\_PL}$	is the line impedance in ohms per desired line length unit (e.g., Ω/mi)

While the relay voltage decreases gradually with increasing SIR (see Fig. 2), a high SIR application is often considered to have an SIR greater than four [1]. We use this SIR value in a couple of examples to calculate the minimum line length for which phase distance elements can be applied without significant concerns.

1) A 500 kV line has an impedance of 0.5 Ω/mi. The interconnecting 500 MVA IBR plant has an impedance of 1.2 pu. Using (23) for an SIR_{MAX} of 4, the minimum line length is 300 miles.
2) A 115 kV line has an impedance of 0.8 Ω/mi. The interconnecting 50 MVA IBR plant has an impedance of 2 pu. Using (23) for an SIR_{MAX} of 4, the minimum line length is 165 miles.

These calculations can be used to gain a rough perspective of distance protection applications when models are unavailable. The relatively long physical line lengths from these examples also reaffirm our understanding that as IBRs replace synchronous generators, practitioners can expect to encounter high SIR applications more frequently and to adjust distance protection as a result.

For example, to prevent a Zone 1 overreach for SIR values significantly greater than 4, its reach should be reduced [5], [6]. If the SIR is too high, Zone 1 should be disabled in favor of communications-assisted or time-delayed backup protection. If the SIR is too high only during contingencies, fault detector (overcurrent) supervision can be used to dynamically block Zone 1 during contingencies. Similarly, it is helpful to verify dependability and coordination margins for overreaching distance zones, as briefly discussed in Section IV-A-3.

V. Conclusion

The SIR of an application corresponds to the relay voltage for line faults and impacts distance protection. This paper reviewed the history and evolution of SIR calculations. Today, the most commonly used SIR calculations use the equations presented in IEEE Std C37.113-2015 (Line Protection Guide) [1], [8]. This paper shows that these equations can have significant inaccuracies. SIR_G and SIR_P can be significantly inaccurate for lines with mutual coupling and lines near IBRs, respectively. Newer and simpler SIR calculations remain accurate for these applications and better align with distance protection because they use only the relay voltage [4].

The older SIR calculations assume a source with equal positive- and negative-sequence impedances, which may not be true for lines near synchronous generators or IBRs. This assumption can result in very significant errors when calculating SIR_P. The paper discusses modeling considerations that can help achieve a more accurate SIR for lines near these sources. Considering both line-to-line and three-phase faults to calculate SIR_P helps account for the differences between the positive- and negative-sequence source impedances. Short-circuit programs can automate these calculations while considering system contingencies. With increasing penetration of IBRs, we can expect to encounter high SIR applications much more frequently. The application guidance presented in this paper can help improve SIR calculations and aid practitioners to better evaluate distance protection applications.

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