Comparison of Third-Harmonic Stator Ground Protection Schemes

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Abstract

Because of the nature of stator winding construction, insulation failure typically results in a ground fault. Various third-harmonic schemes are used to provide neutral-side stator winding protection for high-impedance grounded generators. Applying such schemes in conjunction with a fundamental neutral overvoltage (59N) element, which protects the top 85–95 percent of the stator winding, provides ground fault protection coverage for 100 percent of the stator winding when sufficient third harmonic is available. This paper compares the performance of different third-harmonic schemes and shows how these schemes can be applied to provide secure and sensitive stator winding coverage.

1 Introduction

In high-impedance grounded generators, faults in the top 85–95 percent of the stator winding can be detected by a fundamental neutral overvoltage (59N) element. However, ground faults near the machine neutral (~15 percent) require detection for the following reasons:

- If a ground fault near the neutral remains undetected, the machine becomes solidly grounded. A subsequent fault will bypass the grounding impedance, resulting in severe machine damage. Fig. 1 shows insulation damage near the neutral caused by a foreign object. Early detection of this condition can reduce insulation damage and the likelihood of a catastrophic subsequent ground fault.
- A series fault can result from the fracture of a conductor or the failure of an electrical joint. The current continues to flow via the arc across the fault point. The arc will vaporize the copper conductor between 8–12 inches before the arc breaks through the insulation wall of the stator core and evolves into a ground fault [1].

Some generator owners prefer to alarm for faults near the neutral terminal (~15 percent) and resolve the issue with a scheduled outage because it should not cause direct damage to the unit. However, the failure mode associated with a series fault evolving to a ground fault near the neutral does cause direct machine damage and requires protection.

Fig. 1. Damage caused by a neutral-side fault.

There are two general approaches for detecting ground faults near the neutral of a high-impedance grounded machine:

1. Third-harmonic schemes use the third harmonic normally produced by most machines. Exceptions include units with a two-thirds short-pitch ratio that notch the third harmonic.

   a. If the terminal PT is wye-grounded, a third-harmonic measurement at the terminal (VT3) is available. In this case, both VT3 and the neutral third harmonic (VN3) measured across a neutral grounding transformer (NGT) are used.

   b. If the terminal PT is open-delta or wye-ungrounded (VT3 unavailable), the third-harmonic neutral undervoltage element (27TN), which uses VN3, is applied.

2. Injection schemes require signal injection across the NGT. The operating principle is that of an insulation tester, where the impedance to ground is measured. If the impedance drops below a threshold, a ground fault is declared. This method requires injection equipment, but it does not rely on the third harmonic produced by the machine and can operate when the machine is at a standstill.

This paper compares the performance of the third-harmonic elements described in 1.a and provides protection guidance. A user may want to apply redundant relays that employ different operating principles using the third harmonic. Understanding the relative performance of the elements allows the proper protection to be applied. In this paper, we assume that both VT3 and VN3 are available.

2 Protection elements

We begin our analysis of third-harmonic protection by focusing on the third-harmonic circuit of the generator. The generator step-up (GSU) delta winding provides third-harmonic isolation from the power system, and the equivalent circuit is shown in Fig. 2.

The distributed stator ground insulation capacitance (C_G) is simplified to an equivalent pi-section split between the terminal and neutral sides. The terminal side has an additional external capacitance contribution (C_X) from the surge capacitor, isophase bus, and transformers. The neutral impedance ($ZN3_{sec}$), when reflected to the primary side, is selected to equal the total capacitive reactance magnitude of C_G and C_X.
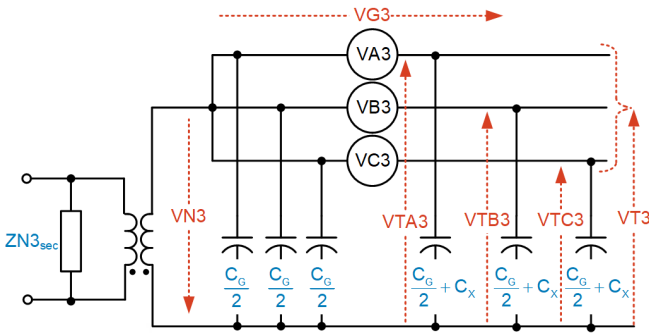

Fig. 2. Third-harmonic pi-equivalent circuit of a unit-connected high-impedance grounded generator.

VT3 and VG3 are the average of the respective per-phase voltages. When a stator ground fault is applied at location m, the circuit is as shown in Fig. 3.
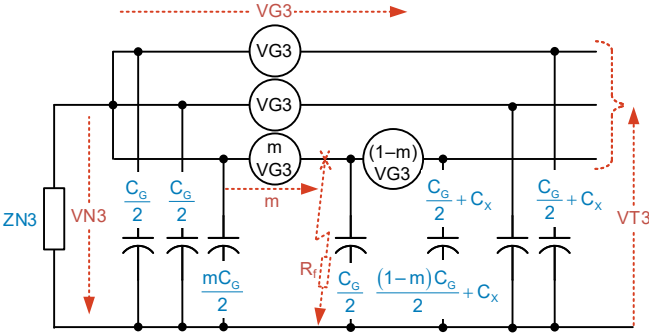

Fig. 3. Effect of an internal ground fault on the generator third-harmonic circuit.

Various approaches can detect a ground fault using the measured quantities VN3 and VT3 [2]–[6]. To develop an understanding of the various implementations, we consider the example system parameters shown in Table 1 for a single-branch machine with a resistive neutral grounding impedance. VG3 is the total third harmonic produced by the machine and is set as the reference (1 pu) to simplify analysis. Similar approaches can be applied to machines with multiple branches and/or resonance-grounded generators.

Parameter	Data
Third-harmonic source (VG3)	1 pu ∠0°
Capacitances (per phase)	Stator ground (C_G): 0.342 μF External (C_X): 0.100 μF
Neutral-grounding impedance (ZN3)	2.0 kΩ equal to $1/(3j\omega[C_G + C_X])$
Nominal frequency	60 Hz

Table 1: Example third-harmonic circuit parameters.

For reference, Table 2 provides several calculated VN3 and VT3 values for various fault resistances (R_f) with a fault location of $m = 0.15$ pu. For a healthy, unfaulted machine $R_f = \infty$. Note that all values are in per unit to facilitate analysis.

R_f	0 Ω	200 Ω	2 kΩ	10 kΩ	∞
VN3	0.15 pu ∠0°	0.21 pu ∠35.5°	0.51 pu ∠29.0°	0.57 pu ∠20.9°	0.58 pu ∠18.4°
VT3	0.85 pu ∠0°	0.84 pu ∠–8.3°	0.61 pu ∠–24.2°	0.51 pu ∠–23.4°	0.48 pu ∠–22.3°

Table 2: VN3 and VT3 for different fault resistances.

2.1 Scheme A

The Scheme A operating equation is defined by (1):

$$\text{Scheme A} = \frac{|VN3|}{|VN3 + VT3|} < PKPA \qquad (1)$$

The phasor sum of VN3 and VT3 always adds to VG3 and the operator, ||, indicates magnitude. The behavior of the third-harmonic circuit in Fig. 3 for different fault resistances is shown in Fig. 4 along with the operating region for Scheme A with a pickup setting, PKPA, set to 0.15 pu.
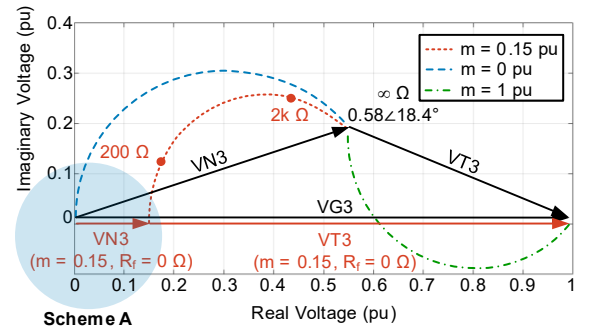

Fig. 4. Effect of fault resistance on VN3 and VT3 with respect to the operating equation of Scheme A.

When the generator is healthy, VG3 drops across the impedance divider circuit defined by the terminal-side capacitances (VT3) and the neutral impedance (VN3). For most installations, the ratio during healthy unit operation is 0.40–0.80. If the neutral impedance is sized too small, the ratio approaches 0.40. If there is a large capacitance external to the machine terminal, the ratio approaches 0.80. For the example, properly sized system, the ratio is 0.58.

During internal metallic faults ($R_f = 0\ \Omega$), VN3 and VT3 are in phase with VG3. For any metallic faults, the ratio in (1) equals the fault location. As R_f increases, VN3 diverges nearly perpendicularly to VG3. This results in an increase in the magnitude of VN3 with an increase in R_f.

Based on the previous analysis, we conclude that Scheme A is a neutral undervoltage element that is normalized by the third harmonic produced by the machine (VG3). The recommended guideline for the pickup setting is the percentage of the stator winding requiring protection. This method does not usually require a survey of the generator and relies on the fact that the neutral grounding impedance is matched with respect to the capacitance around the generator. The denominator of the ratio is a phasor sum, hence the NGT polarity needs to be consistent with Fig. 2.

In some implementations [2], Scheme A has the additional terminal-overvoltage supervision shown in (2):

$$\frac{|VT3|}{|VN3+VT3|} > (1 - PKPA) \tag{2}$$

Mathematically, the Scheme A operating equation (1) is a subset of the overvoltage supervision in (2), hence there is no benefit to this supervision in a digital relay.

In some implementations [3], (1) is rearranged into (3), where β is a security-bias factor, mathematically the inverse of PKPA, which in turn corresponds to the physical per unit of the stator winding protection desired.

$$|VN3+VT3| > \beta \cdot |VN3| \tag{3}$$

Generators typically produce VG3 in the range of 1–10 percent of the generator nominal line-to-neutral voltage (VLN), depending on pole shape, winding functions, loading, and saturation. Scheme A includes a minimum supervision (e.g., VG3 > 1%) to ensure that valid voltages are compared and that the element has adequate security for external third-harmonic events such as those described in Section 3.

2.2 Scheme B

The Scheme B operating equation is shown by (4):

$$\text{Scheme B} = |RAT \cdot |VT3| - |VN3|| > PKPB \tag{4}$$

RAT is a setting obtained via a survey during commissioning. Typically, VT3 and VN3 are measured over a range of generator loadings and RAT is calculated as the average of |VN3| divided by the average of |VT3|. For our example, RAT = 1.20, which indicates that the neutral impedance is 1.20 times the terminal capacitive reactance. The PKPB setting provides security, but it is set with the intent of providing 100 percent stator-winding coverage when combined with a 59N element. One setting criterion is given by (5):

$$PKPB = 1.1 \cdot \left(0.1 + MAX\left\{||VN3| - RAT|VT3||\right\}\right) \tag{5}$$

Note that a highly linear correlation between the survey values of VT3 and VN3 translates to a sensitive pickup setting. For this reason, a thorough survey is recommended.

Scheme B compares a differential of the magnitudes, hence the element behavior for a fault can be represented as shown in Fig. 5. Because the element looks at magnitudes, the NGT polarity does not need to be consistent with Fig. 2.

Based on the ratio of the impedances during healthy unit operation, at Point O in Fig. 5 the third-harmonic voltage with respect to ground is zero. This point is defined by (6). For our example, O resides at 0.55 pu and indicates that a metallic fault at 55 percent of the winding will not be detected by Scheme B.

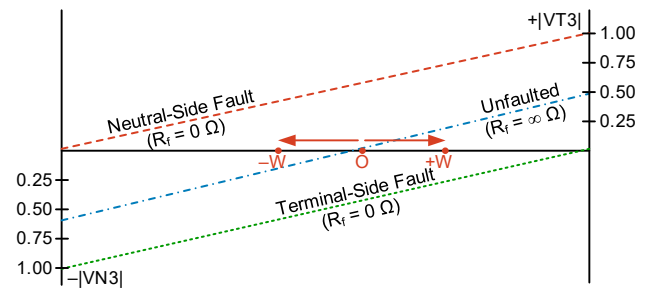$$O = \frac{|VN3|}{|VN3| + |VT3|} = \frac{RAT}{1 + RAT} \tag{6}$$

Fig. 5. Operating characteristic of Scheme B.

PKPB is a security margin, and setting guidance is provided in Section 3. PKPB introduces a region around Point O ($\pm W$) where the element remains inoperative for metallic faults, as defined by (7), (8), and (9).

$$W = \frac{1}{VG3}\left(\frac{PKPB}{1 + RAT}\right) \tag{7}$$

$$\text{Lower Winding} = O - W \tag{8}$$

$$\text{Upper Winding} = O + W \tag{9}$$

For instance, with a PKPB of 0.85 pu, W = 0.39 pu, providing coverage to 16 percent of the lower winding. As the machine produces a larger VG3, the protected region increases and the element gains sensitivity. Consequently, if VG3 is smaller than PKPB/RAT, the element provides no neutral-side coverage.

2.3 Scheme C

If we set PKPB = 0, (4) can be rearranged to form the Scheme C operating equation shown by (10):

$$\text{Scheme C} = \frac{|VT3|}{|VN3|} > PKPC \tag{10}$$

PKPC is obtained via a survey during commissioning, and a security margin is provided on top of the ratio obtained during healthy unit operation. With the security margin lumped into the ratio of VN3 and VT3, the element can lose security when the third harmonic produced by the machine (VG3) is small. For example, when VG3 = 0 pu (with VT3 = VN3 = 0 pu), the

ratio of VT3 and VN3 is undefined, possibly resulting in unexpected behavior from Scheme C because of measurement errors. While Schemes B and C are similar in nature (i.e., both look for a deviation from the healthy machine characteristics), Scheme B does not suffer from this problem because of a separate setting (PKPB).

In some implementations [4], positive-sequence voltage (V1) supervision is required to address the Scheme C security problem based on the premise that sufficient V1 indicates sufficient VG3. However, this assumption may not always be valid, as in the case where the machine operates as a synchronous condenser. An alternate solution is to supervise the element with a VG3 check (e.g., VG3 > 1%), as is done for Scheme A.

2.4 Scheme D

The Scheme D operating equation is defined by (11):

$$\text{Scheme D} = \left| \text{RAT} \cdot \text{VT3} - \text{VN3} \right| > \text{PKPD} \cdot \left| \text{VN3} \right| \quad (11)$$

The core operating principle is the same as that of Schemes B and C discussed previously. The element requires a survey and looks for deviations from a healthy distribution.

The left side of (11) is similar to the Scheme B operating equation. The distinction is that it includes phasor information and that RAT is a complex value.

The right side of (11) scales with VN3. The resulting problem is the same as the Scheme C element, where at low values of VG3, the element security can be jeopardized.

3 Security

Third-harmonic protection schemes rely on the circuit to behave as a voltage divider for two fixed impedances. This is not always the case, which negatively impacts element security. In this section, we review several real-world cases that challenge the security of third-harmonic schemes. Some of the cases are balanced and apply to all three phases, hence the analysis can be simplified from Fig. 3 to an equivalent zero-sequence circuit like the one shown in Fig. 7.

3.1 Factors influencing security

3.1.1 PT secondary faults

For a fault on the secondary side of the terminal PTs, an external impedance is introduced to the circuit. On a 24 kV, 800 MVA unit, the transformed impedance on the primary circuit is 8 kΩ. Schemes B and D can misoperate for this condition, as shown in Fig. 6. Time coordination of the element with the PT fuses may be considered for these schemes. Some relay manufacturers provide a method to only detect faults in the lower winding region, thereby providing security for PT secondary faults.

Secondary faults can also occur across the NGT, as shown in Fig. 6, but this condition requires detection because it shorts the neutral side of the machine.
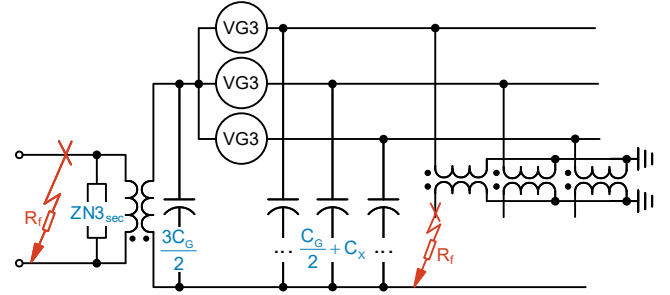

Fig. 6.   Secondary side fault locations.

3.1.2 System events

Power system faults and switching events on the GSU high side can present an external third-harmonic source. This source can couple via the GSU interwinding capacitance to generate an error quantity (ε) that may add to or subtract from VT3 and VN3, respectively, as shown in Fig. 7.
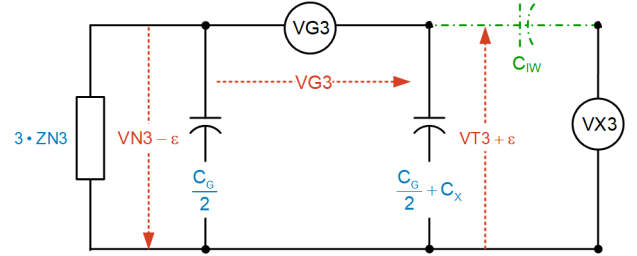

Fig. 7.   Coupling of GSU high-voltage events.

The voltage transients from these events depend on the network impedances (e.g., long lines have lower natural frequencies). The frequency response of a third-harmonic filter (60 Hz nominal) is shown in Fig. 8. The filter attenuates (but does not notch out) the higher frequencies from system events. Fortunately, these transients do not last too long (typically less than 50 ms), so a time delay larger than 100 ms (e.g., 500 ms) provides the required security.
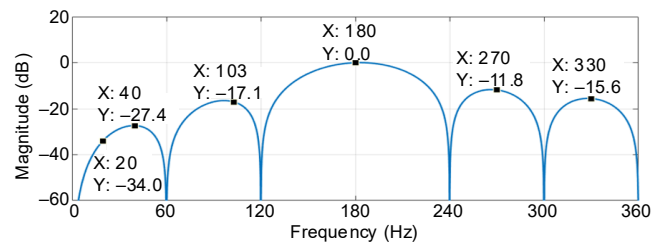

Fig. 8.   Third-harmonic filter characteristic for some digital relays.

3.1.3 GSU events

Nonlinear GSU events, such as inrush, can present an external third-harmonic source [7]. The coupling is not direct because the GSU low-voltage winding is connected in delta; indirect coupling occurs through the interwinding capacitance, similar to Fig. 7. For one such event [8], $C_{IW} = 8$ nF and $VX3 = 6$ kVLN (2 percent of a 525 kVLL system), causing third-harmonic element misoperation. These events can last a few seconds. Adequate security must be built into the scheme pickup settings, as will be discussed in Section 3.2.

3.1.4 Modification of stator ground capacitance

The distributed stator ground capacitance of a generator originates from the insulation and varies with temperature (due to machine loading), moisture content, and age. While these factors provide minor capacitance deviations, large changes can occur as the result of the failure of the generator cooling system, for instance.

A field event captured by a 64S relay, which measures generator stator ground impedance, is shown in Fig. 9. The cooling system was accidentally left off in Region D, and the insulation resistance and capacitive reactance dropped to 13.9 kΩ and 1.74 kΩ, respectively, almost resulting in a fault.
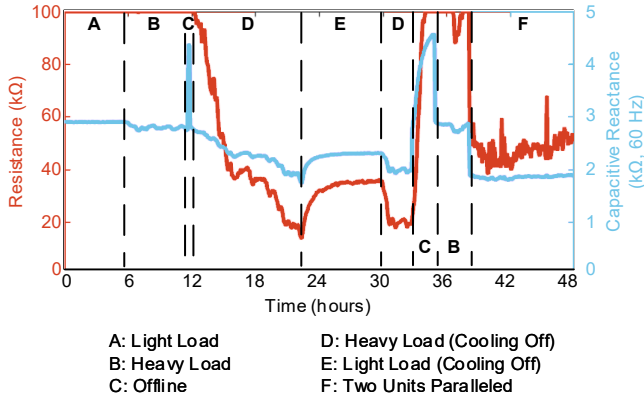

Fig. 9.   Field event showing stator ground impedances for various machine states over a two-day period.

These conditions will not be detected by third-harmonic schemes unless a neutral-side fault occurs because of the cooling system failure. Adequate security must be built into the scheme pickup settings, as will be discussed in Section 3.2.

3.1.5 Impedance profile change at generator terminal

Some generators have a low-voltage breaker with a surge capacitor on the GSU side of the breaker. In such cases, the impedance of the third-harmonic circuit can change significantly, depending on the breaker state [3]. This behavior can be seen in Fig. 9. When the unit is online in Region A or B (relative to the offline state shown in Region C), the additional surge capacitance reduces the impedance significantly. Some relays provide alternate settings to tackle this problem [3].

Abnormal conditions, such as water ingress or other contamination of the isophase bus, can also modify the terminal-side impedance. Adequate security must be built into the scheme pickup settings, as will be discussed in Section 3.2.

3.2 Security analysis and scheme settings

Having reviewed scenarios that challenge third-harmonic protection, we now compare the security of individual schemes. We do this through the artificial introduction of an external source (ε) that adds to VT3 and subtracts from VN3, as shown in Table 3. We solve the circuit of Fig. 7, apply the resulting voltages to each scheme and determine the pickup threshold that causes each scheme to operate. In determining the pickup setting, we also consider the following manufacturer recommendations:

- Schemes C and D require a margin of approximately 50 percent, which corresponds to $\varepsilon \sim 0.10$ pu.
- Schemes A, C, and D require a minimum VG3 supervision of 1 percent.
- Scheme B does not require supervision; this security is built into the PKP.

The results are given in Table 3.

ε (pu of VG3)	Scheme A PKP	Scheme B PKP	Scheme C PKP	Scheme D PKP
0.00	0.58	0.00	1.00	0.00
0.10	0.48	0.20	1.41	0.43
0.20	0.38	0.40	2.04	1.08
0.28	0.30	0.56	2.87	1.92
0.43	0.15	0.88	6.79	5.85

Table 3:   Required secure pickup settings for varying levels of ε.

Note that the pickup settings of Schemes A and B are linear with ε, whereas Schemes C and D are quadratic and diverge very quickly. Based on field cases that demand high security, the above data should be considered at VG3 = 2% V_{LN}. This only affects the setting calculations of relays using Scheme B, which then becomes 0.88 pu • 2% $V_{LN} \approx 1.75\% V_{LN}$.

4   Sensitivity

In Section 3, we determined settings for each scheme that provided equal levels of security for an external event. We now compare the sensitivities of each scheme. To do this, we solve the circuit of Fig. 3 while varying the fault location and resistance. The resulting voltages are fed to each scheme, and we check the operation.

Using the secure ($\varepsilon = 0.43$) settings, we show the resulting coverage and resistive sensitivity provided by the various elements in Fig. 10. The 59N sensitivity with a pickup of 0.05 pu is shown as a reference.
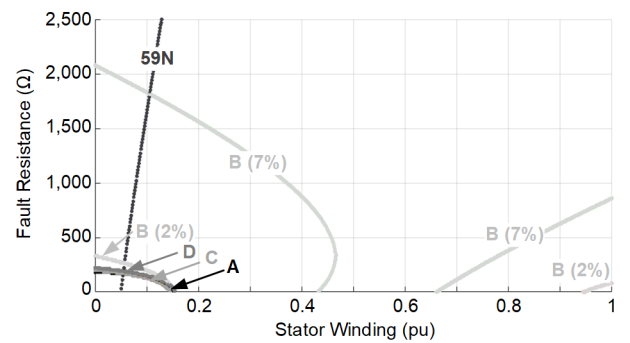

Fig. 10.   Sensitivity provided by ground fault protection elements with secure settings ($\varepsilon = 0.43$ pu).

Note that Schemes A, C, and D have fixed characteristics. The characteristic of Scheme B varies with VG3, shown as a percentage in Fig. 11. Two typical values are shown for no-load (2%) and full-load (7%). At low levels, its resistive sensitivity is similar to that of the other schemes, but when VG3 is large, its sensitivity is much higher.

We repeated the exercise for a less conservative case ($\varepsilon = 0.20$), and the results are shown in Fig. 11.
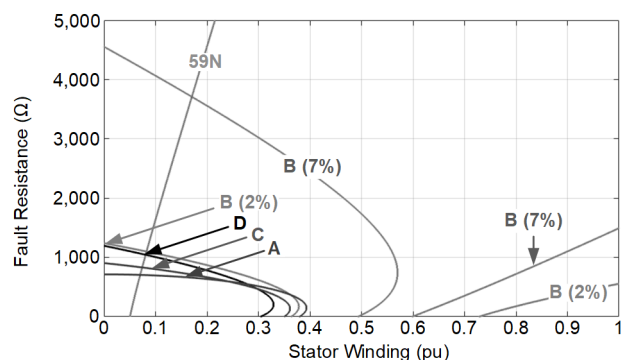

Fig. 11.   Sensitivity provided by ground fault protection elements with sensitive settings ($\varepsilon = 0.20$ pu).

The primary sensitivity requirement for generator protection is to provide metallic fault ($R_f = 0\ \Omega$) coverage for 100 percent of the stator winding. For our example system, all schemes provide this coverage for both sensitive and secure settings. For faults in the upper 90 percent of the winding, the 59N element provides very high resistive coverage; the performance of third-harmonic schemes is not a concern in this region. Note that the schemes may operate for a resistive fault, but not for a metallic fault, at the same location.

All schemes can be set to provide similar levels of security and sensitivity at a given VG3, although this is not evident from an examination of the operating equations. Furthermore, manufacturers do not normally provide these comparisons.

We are not aware of any guidance with respect to minimum resistive coverage. However, for faults in the early stages of inception, a large fault impedance can be expected. Scheme B is most likely to detect the condition at full load with a lagging power factor (when VG3 is large). If sensitive detection for such conditions is desired, a sensitively set Scheme B with PKPB = 0.40% V_{LN} ($\varepsilon = 0.20$ pu, as shown in Fig. 11) can be used to alarm.

5 Conclusion

Various implementations of third-harmonic schemes are in use. All third-harmonic schemes can be set to provide similar and adequate security. When combined with a 59N element, all schemes provide sufficient neutral-side coverage to obtain 100 percent metallic fault coverage for stator ground faults when sufficient third harmonic is available.

Scheme A is the easiest scheme to set because the pickup setting correlates directly to the winding coverage for metallic faults. Scheme B provides the highest sensitivity, especially when the generator produces a large amount of third harmonic. A higher sensitivity may be desired for incipient faults.

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