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Ground Protection Methods for Transmission Lines using Segmented Static Wires

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SUMMARY

Ground protection setting philosophies are investigated after the discovery of flashovers on segmented shield wires following an actual fault event. A line-to-ground fault occurred in a transmission line zone inside a 500 kV substation fence. The substation consists of two 500 kV lines protected with a mix of impedance and differential schemes. These 500 kV lines were constructed such that their static conductors are segmented throughout their path from substation to substation, thereby eliminating the circulating currents between the grounded towers and the static. The line differential relays on both lines operated correctly. Local impedance-based protection at the substation operated as designed. However, the impedance-based protection at both remote terminals tripped on high speed by underreaching Zone 1 ground elements for a fault at the local substation. Post-event analysis showed the static conductor path became continuous during the fault event due to the induced voltage on the static causing a flashover at the segmentation points. This effectively made the zero-sequence impedance much smaller in magnitude, resulting in the Zone 1 ground element tripping for a fault at the remote terminal. This paper outlines the analysis required to quantify the event and analyses how to properly set ground protection for segmented static lines.

KEYWORDS

Power system protection, Zero sequence impedance, Segmented static conductors, Induced voltage

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I. INTRODUCTION

As the need for reliable electricity grows and transmission line Right-of-Way (ROW) space becomes increasingly limited, many utilities are exploring ways to bolster efficiency in the infrastructure they already own. One source of losses in transmission lines occurs because of the mutual coupling between the static and phase conductors. A voltage is induced in the shield wires due to Faraday's Law of Induction [1]. Depending on how the shield wire is grounded, a closed circuit, comprised of the static wires, their supporting structures, and the ground can be formed. If this loop exists, an induced current will flow and cause heat to accumulate, directly resulting in I2R power losses.

$$V_{ind} = \oint \vec{E} * d\vec{l} \tag{1}$$

To eliminate this continuous path, Dominion Energy uses a strategy known as "Static Wire Segmentation." Instead of grounding the shield wires at every tower, the statics are only grounded at certain towers (see Figure 1). Then, they are segmented at adjacent structures using insulators, thereby removing the closed loop [1].

The insulators used at the isolation points usually contain spark gaps that allow them to flash over if a certain voltage threshold is reached [1]. For example, when lightning strikes, it is important that the static wires behave as a continuous loop, so the energy is safely dissipated into the ground. However, lightning is not the only event which produces a voltage sufficiently large enough to cause a flashover. Ground faults on the transmission line can produce sizeable currents in the phase conductor that may induce enough voltage on the static conductor to arc over the spark gap. When this occurs, the zero-sequence impedance of the transmission line can drastically change, introducing issues for distance-based ground protection. Distance elements set using the segmented static impedance may be inadvertently overreaching, since the effective impedance is much smaller when the static flashes over. This exact situation occurred on a Dominion Energy transmission line, prompting further analysis.

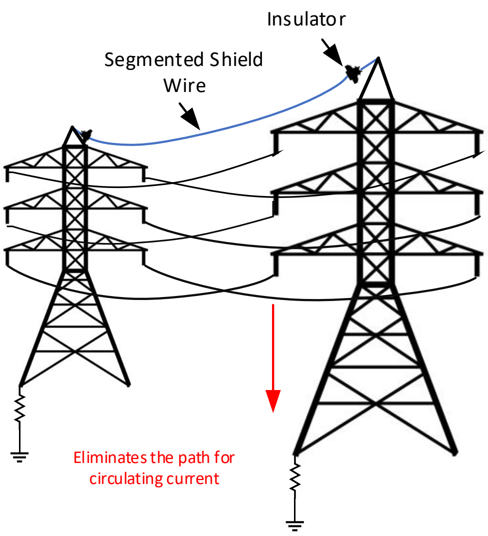

Figure 1. Segmented Shield Wire

In this paper, we describe the initiating event via the relay operations that occurred at nearby substations. Then we describe how we replicated the situation in PSCAD so that initial assumptions could be quantified. An overview of Dominion Energy's impedance calculation process follows, along with a description of the changes necessary to account for the segmentation-point flashover phenomenon. Impacts to several different types of ground protection are explored, and solutions to mitigate them are then given.

II. GROUND PROTECTION MIS-OPERATION EVENT REVIEW

A. Event Description

At Dominion Energy 500 kV Substation B, a C-G fault occurred inside the protection zone of Line 2, as shown in Figure 2. The two 500 kV transmission lines are protected with a mix of schemes, including Directional Comparison Blocking (DCB) and Line Differential. The line differential relays for Line 2 operated correctly and isolated the fault at both terminals. Additionally, the local impedance-based protection for the faulted line tripped on the high-speed underreaching Zone 1 ground element, as designed. The local DCB relay for Line 1 correctly detected the fault in the reverse direction and sent a blocking signal to the remote terminal.

However, the impedance-based relay located at Substation A incorrectly tripped on the Zone 1 ground element. The high-speed underreaching Zone 1 did not wait for a blocking signal and tripped as soon as the set impedance characteristic was detected. Since the location of the ground fault was known, it was unclear during the initial investigation why Line 1 also tripped on the high-speed underreaching protection.

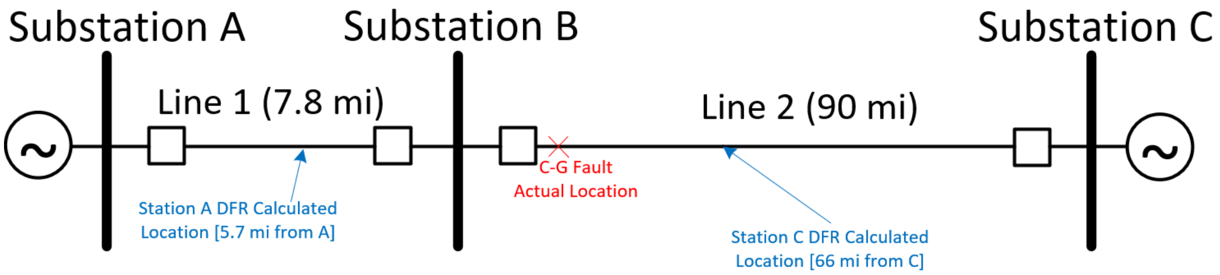

Figure 1. Power System Topology at Mis-Operation Location

Adding to the mystery surrounding the relay mis-operation, the Digital Fault Recorders (DFR) at Substations A and B could not properly locate the fault. The fault recorders at the two remote stations claimed the fault location was on their respective lines and a considerable distance short of the actual location. Since DCB schemes and fault locating functions rely heavily on calculated transmission-line impedances, it was likely the transmission lines were modeled incorrectly. Dominion Energy models lightning protection static conductors for 500 kV transmission lines as open circuits. This modeling practice is done because these wires are segmented at various points in the line and then grounded, thereby eliminating a continuous path from terminal to terminal. If the static wires were not segmented, a continuous circuit would exist in parallel with the phase conductors, which could drastically affect the zero-sequence impedance of the line. However, segmented wires can behave continuously under the right circumstances. When a lightning strike hits the shield wire, an induced voltage is developed across the insulator and a flashover occurs when the basic insulation level (BIL) is exceeded [1].

During the root cause analysis of this event, it was discovered that the fault current in the phase conductor induced enough voltage on the static conductors to cause a flashover at the segmentation locations. Ultimately, this caused the static conductors to become a continuous path for fault current, which significantly altered the zero-sequence impedance of the transmission line. This change in the zero-sequence impedance of the line during the fault condition caused the Zone 1 ground element to overreach the remote terminal, rather than underreach as designed. The impedance measured by the Substation A relay during the fault is shown by the blue line in Figure 3. As the measured impedance moved closer to the ground quadrilaterals, it first entered the characteristic for Zone 2. This was to be expected, as Zone 2 was set to cover more than 100% of the line impedance. The trajectory then continued downward and eventually reached Zone 1, causing the instantaneous trip. Figure 3 shows that Zone 1 is intended to cover approximately 80% of the transmission-line impedance. When the fault occurred at Substation B, the measured impedance was expected to be at the top of the black line in Figure 3. Instead, the flashover between two segmented points caused the zero-sequence impedance of the line to change, placing Substation B within the Zone 1 quadrilateral.

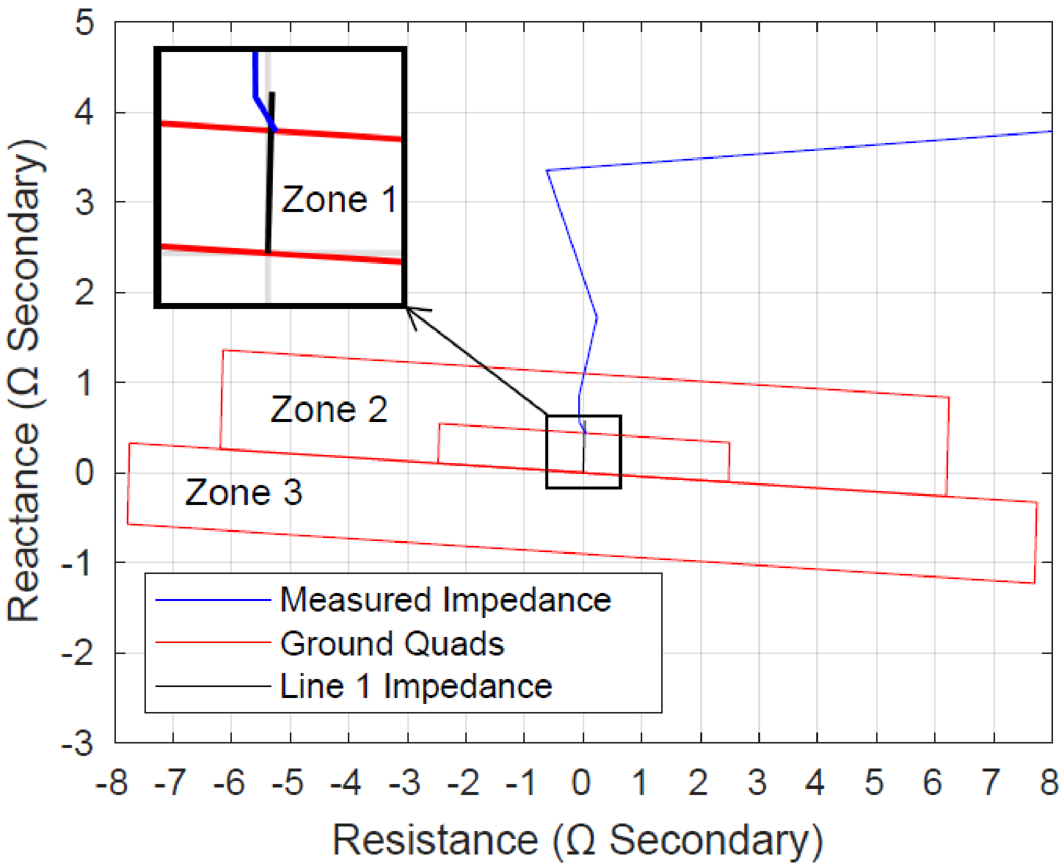

Figure 2 Relay Response at Station A

This was verified with the event data from the DFR by empirically adjusting the Z_0 impedance of the line in software until the data provided the correct fault location. The remote terminal of the faulted line also tripped on Zone 1 ground as well. While isolation of the fault was correct for the faulted line, the operation of Zone 1 ground was not intended and was caused by the same flashover of the static conductor segmentation sections.

B. Segmentation Point Flashover Simulations

After the fault current was recorded by the DFR at Substation A, it became evident that fault currents of large magnitude would also induce a voltage substantial enough to flash over the segmentation points. A replica of the event was modeled in PSCAD to analyze the simulated induced voltage. The porcelain insulators on the 500 kV transmission line are rated at 10 kV for a wet flashover and 20 kV for a dry flashover. When the fault occurred, it was snowing, so therefore a 10 kV threshold was assumed. Figure 4 shows the locations of the four porcelain insulators at the segmentation points and where an induced voltage was produced.

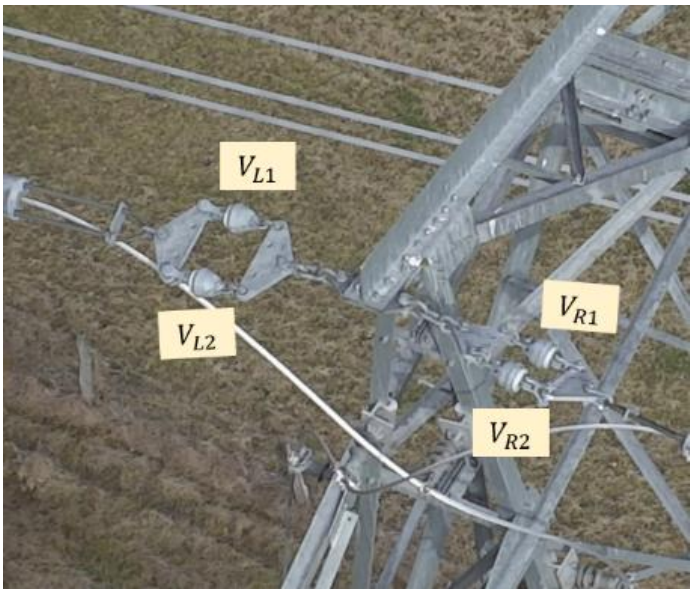

Figure 4. Induced Voltage Across Insulators on the 500 kV Transmission Line

The DFR at Substation A recorded a fault current of 16.35 kA. The line-to-ground fault event is illustrated in Figure 5. An average sag height was incorporated between sections when constructing the model. During the simulation a 16 kA fault was applied (Figure 5).

Figures 5–9 illustrate the induced voltage across the insulators during the fault.

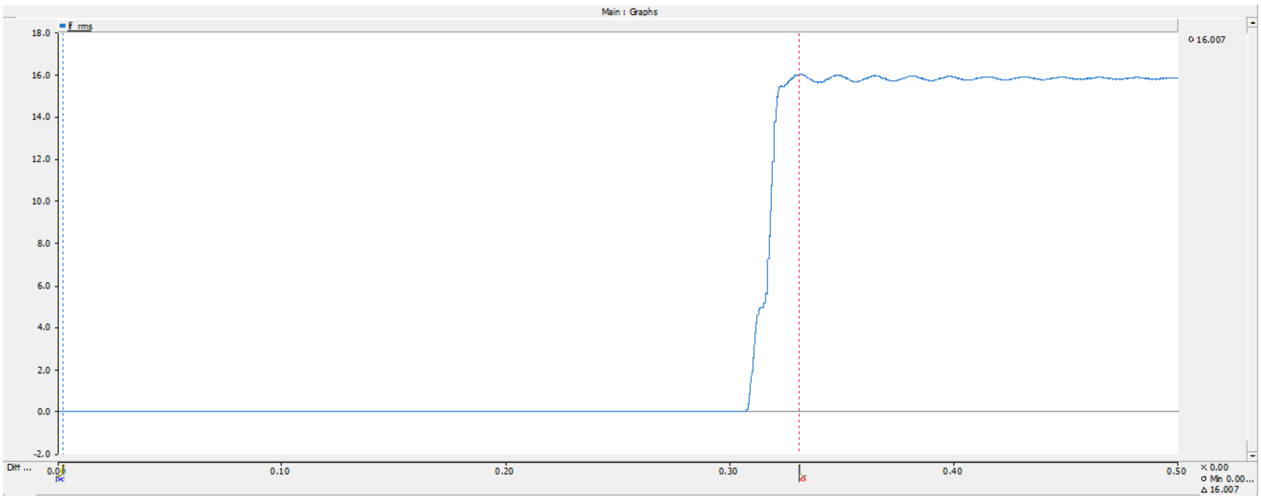

Figure 5. Simulated Fault Current (kA RMS) from Substation A in PSCAD

The induced voltages across the 4 insulators was:

1. 25.67 kV (V_{L_1})
2. 27.15 kV (V_{R_1})
3. 25.69 kV (V_{L_2})
4. 27.17 kV (V_{R_2})

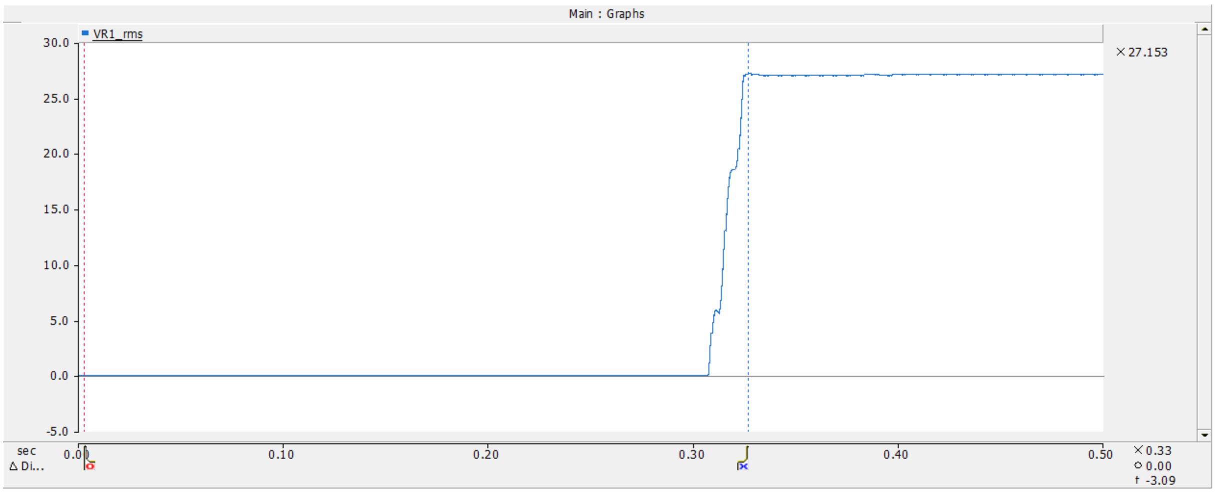

Figure 6. Induced Voltage on the Left Insulator (V_{L_1})

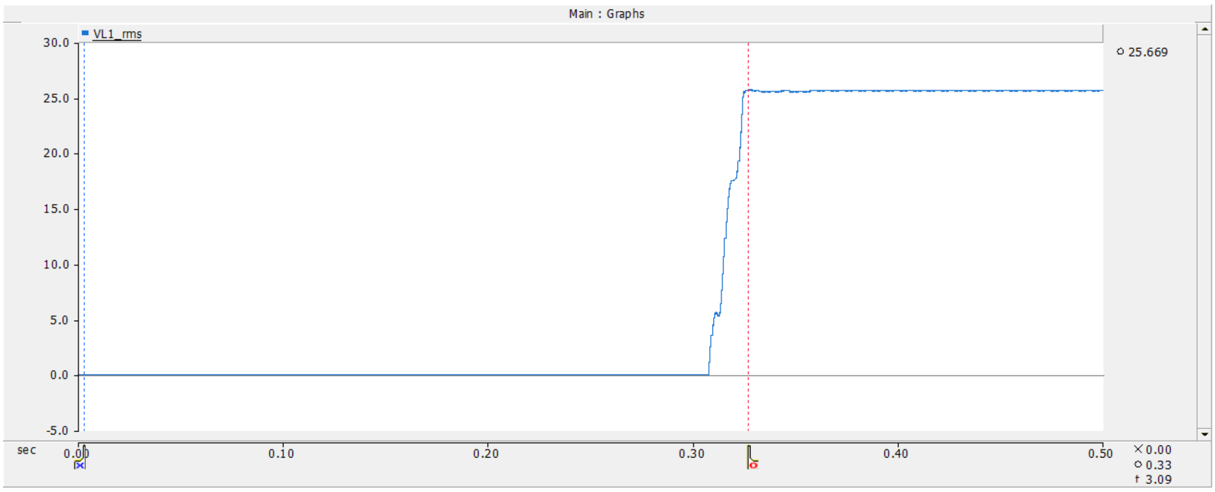

Figure 7. **Induced Voltage on the Left Insulator (V_{L_2})**

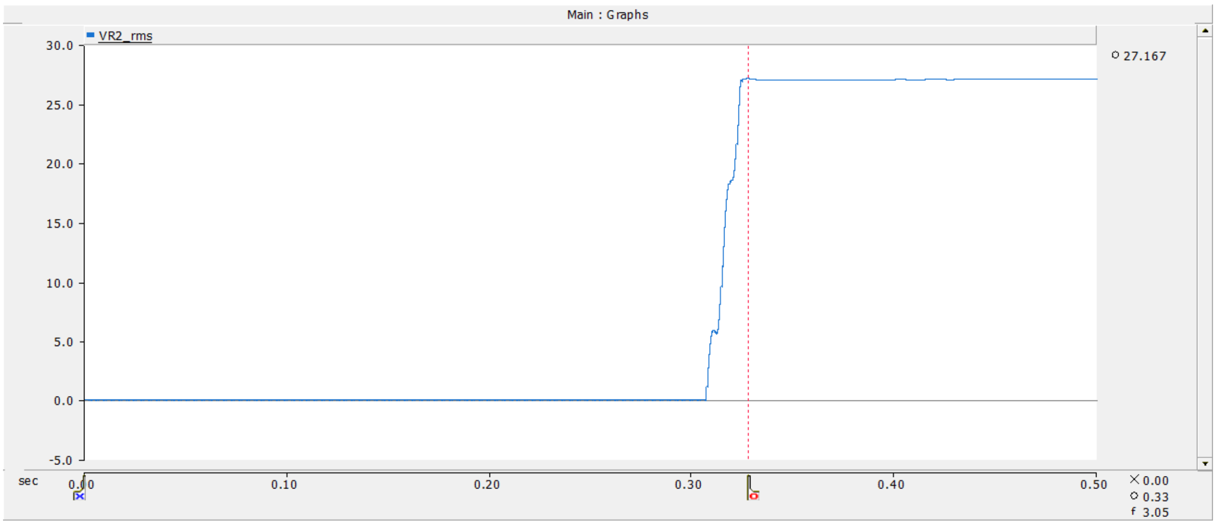

Figure 8. **Induced Voltage on the Right Insulator (V_{R_1})**

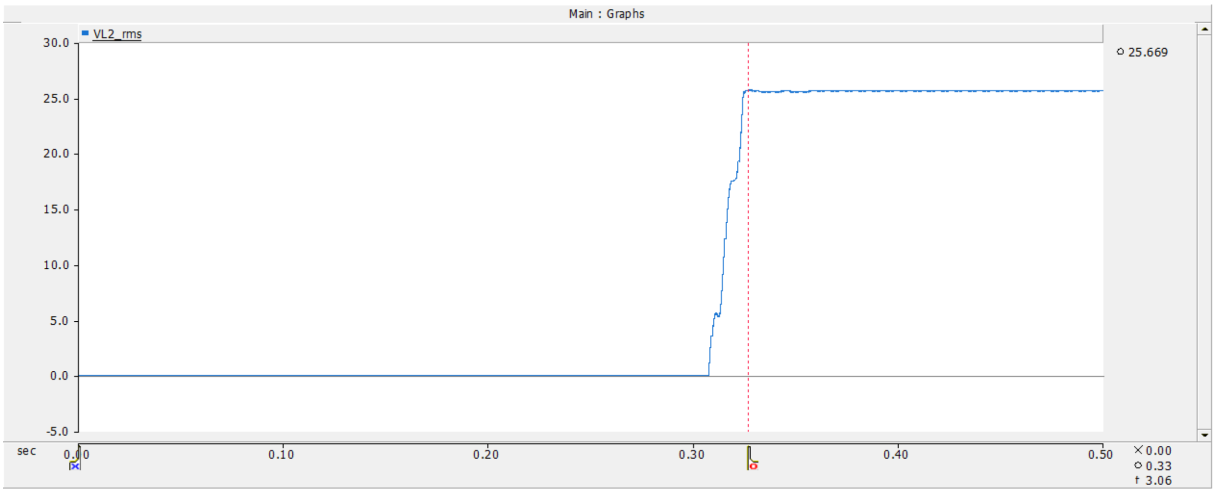

Figure 9. **Induced Voltage on the Right Insulator (V_{R_2})**

The insulators installed at the segmentation points on Line 1 are more than 10 years old. Over time, several factors can degrade an insulator's performance, including temperature, moisture, contamination, mechanical vibration, and electrical stress [2]. Aging insulators can gradually deteriorate and reduce the electrical strength. Climate events such as ice storms can also produce extreme mechanical stress [3].

These simulations prove that a significant amount of induced voltage across the insulator can be generated from a fault condition. This can cause sufficient induced voltage to be created to exceed the threshold and result in a flashover. Since the rated BIL is 20 kV, a flashover will be produced, creating a continuous grounded shield wire between the line terminals.

III. HISTORICAL PROCESS OF TRANSMISSION LINE IMPEDANCE CALCULATION

Dominion Energy models transmission lines using a construction program to display cross-sectional views of the line. In this program, construction information about the transmission line is entered, including the conductors' horizontal and vertical positions, conductor type, presence of bundled conductors, soil resistivity, and static conductor type and size. An example of the two-dimensional view can be seen by Figure 10, where a 500 kV transmission line occupies the same right-of-way (ROW) as a 115 kV line and a 230 kV line.

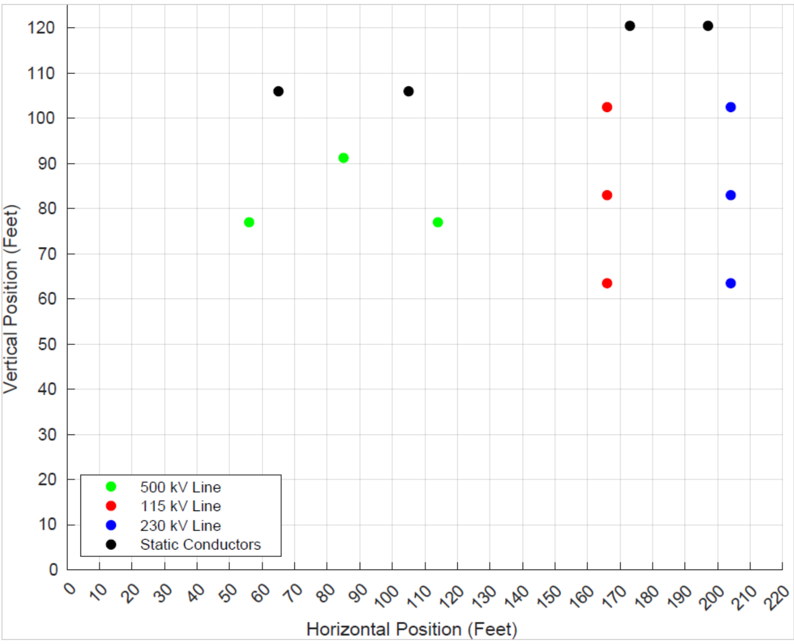

Figure 10. Cross-Sectional View of Transmission Line Constructions

Sometimes static conductors may be segmented to remove the closed loop that enables wasteful circulating currents. At Dominion Energy, this is mostly done on the 500 kV transmission lines, some lower voltage lines that are underbuilt on a 500 kV structure, and some lower voltage lines that intersect 500 kV lines. The shield wires contribute a mutual impedance to the zero sequence parameters of the line, assuming they run continuously from terminal to terminal. However, if the wires are segmented, there is a negligible effect on the line impedance [4].

Dominion Energy has historically modeled segmented shield wires by removing their construction data from the program, since it was assumed that no flashovers occurred at the segmentation points. While the construction software offers an option to specify if the shield wires are segmented or not, this introduces another issue. Other transmission lines may occupy the same ROW with continuous static conductors. If the segmented static option in the program is selected, all static conductors on all lines in the same cross-section will be modeled with segmented statics. To only model the static for the line under study, the preferred method was to delete the static wires only for the segmented line. Any other lines in parallel with continuous statics retained their construction information since it significantly affects their zero-sequence self-impedances.

IV. FUTURE METHOD FOR CALCULATING TRANSMISSION-LINE IMPEDANCE

After the initiating event, it became clear that the previous practice of calculating line impedances needed to be changed. Several variables provide challenges: Due to environmental factors as well as the fault magnitude, it is unknown if any neighboring lines near the fault will have the static conductors flash to the transmission towers. It is also unknown if the static conductors on the line of study will flash to the tower for a fault on a remote line. Therefore, a short-circuit study would need to ensure relay selectivity in the event the static conductors are segmented from terminal to terminal, as well as in the event the static conductors become continuous due to the segmentation point flashovers.

In our modeling, the transmission-line impedance calculation with segmented static conductors remains unchanged. The additional line impedance calculation going forward now accounts for flashover of static conductors at the segmentation points. One of the unknowns going into this additional analysis is how many segmentation points will flashover to the transmission towers. Different transmission line constructions may exist at each segmentation point, affecting the magnitude of induced voltage. Additionally, the insulators could have varying degrees of degradation due to environmental factors. From a relay-setting perspective, it would be conservative to assume that the static conductors become fully continuous from station to station. This would ensure that any unrestrained high-speed underreaching elements do not overreach the remote terminal.

The additional analysis needs all static conductors to be included in the transmission line cross-sectional view, while ensuring any computer-aided software is set to have all static conductors for all lines in all cross-sectional views. This will result in a conservative total zero sequence impedance which is less than the zero-sequence impedance calculated with segmented static conductors.

V. IMPACTS TO GROUND PROTECTION

A. Underreaching Distance Protection

Historically, setting the ground distance protection was done with line impedance parameters calculated using the segmented static conductors. Based on the operating experience from the event described in this paper, a new setting philosophy is needed for the ground distance underreaching protection.

Since the impedance is now calculated with a continuous static along with segmented static conductors, it is conservative to assume the static conductors flash at all segmentation points and the static conductors are continuous from station to station during a fault condition. When setting the ground distance protection, an important consideration is the zero-sequence compensation factor. As described in [5], the zero-sequence compensation factor is calculated as follows:

$$k_0 = \frac{Z_{0L} - Z_{1L}}{3 \cdot Z_{1L}} \tag{2}$$

where:

Z_{0L} = Zero-Sequence Line Impedance

Z_{1L} = Positive-Sequence Line Impedance

The relay then uses the zero-sequence compensation factor in (2) to calculate an apparent impedance using the following equation, as shown in [5]:

$$Z_{APP} = \frac{V_a}{(I_a + k_0 \cdot 3I_0)} \tag{3}$$

Depending on how the pilot protection is set, there are two methods for setting the underreaching ground protection:

(1) If the communication protection scheme is using pilot overcurrent protection, the Zone 1 ground protection can be set using 80% of the line's apparent impedance with segmented static conductors. The zero-sequence compensation factor, however, would be set using k_0 with Z_{0L} and Z_{1L} line impedance parameters with continuous static conductors. This can be done, since the only setting using the zero-sequence compensation factor is Zone 1 ground; the overcurrent settings are not dependent on the additional compensation factor. Dominion Energy does not normally use pilot overcurrent protection, but there are a few cases where pilot overcurrent is used.

(2) If the communication protection scheme is using pilot distance protection, the Zone 1 ground protection would need to consider the line impedance with continuous static conductors while using k_0 with Z_{0L} and Z_{1L} line impedance parameters with segmented static conductors. Some relays have advanced settings allowing users to select different k_0 for each zone. The standard at Dominion Energy is to not use the advanced ground settings, so a single zero-sequence compensation factor is selected for all impedance zones. In fault simulation software, faults would need to be taken at the end of Zone 1's reach; but the compensation factor would need to be changed in the short-circuit model so that the apparent impedance seen by the line protection is calculated correctly.

i. Example Calculation of Zone 1 Reach

Consider a line with the following parameters:

$$ZL_1 = 9.76\angle 87.5°$$
$$ZL_{0,Segmented} = 39.41\angle 82.4°$$
$$k_{0,Segmented} = 1.014\angle -6.82°$$

For the purposes of this example, the fault currents seen by the transmission line relay for a remote bus L-G fault (assuming none of the segmentation points flash over) are as follows:

$$V_a = 100.29\angle 29.5° \text{ kV}$$

$$3I_0 = 4240\angle -55.0° \text{ A}_{\text{Primary}}$$
$$I_a = 5640\angle -54.8° \text{ A}_{\text{Primary}}$$

Using Equation (3), the apparent impedance seen by the transmission-line relay would equate to:

$$Z_{App,Segmented} = 10.11\angle 87.3° \ \Omega_{\text{Primary}}$$

The result would be setting Zone 1 ground to 80% of the apparent impedance, using the line impedance with segmented static conductors. The maximum torque angle for the ground protection is normally set to the positive sequence impedance angle.

$$Z1G_{segmented} = 80\% \cdot \left|Z_{App,Segmented}\right| \angle(ZL_1)$$
$$= 8.08\angle 87.5° \ \Omega_{\text{Primary}}$$

Using the same line, when zero-sequence impedance and the corresponding k_0 factor of the line is recalculated, the result is:

$$ZL_{0,Continuous} = 23.58\angle 74.01° \ \Omega_{\text{Primary}}$$
$$k_{0,continuous} = 0.487\angle -22.67°$$

However, the fault current seen by the transmission line relays for a remote L-G bus fault ,if all the segmentation points flashover and the static conductors become continuous from terminal to terminal, is as follows:

$$V_a = 85.06\angle 27.3° \text{ kV}$$
$$3I_0 = 5122\angle -52.2° \text{ A}_{\text{Primary}}$$
$$I_a = 6036\angle -53.8° \text{ A}_{\text{Primary}}$$

The limitation of the digital relay causes the user to select a single k_0 compensation factor. Depending on which factor is used, different results can be seen. However, the resulting apparent impedance if $k_{0,continuous}$ is used may not be surprising.

$$Z_{App,Continuous,k0segmented} = 7.58\angle 87.5° \ \Omega_{\text{Primary}}$$
$$Z_{App,Continuous,k0continuous} = 10.11\angle 87.3° \ \Omega_{\text{Primary}}$$

Based on the new fault data with a continuous static, Zone 1 ground would be set in the same manner as before, using $k_{0,continuous}$. If $k_{0,segmented}$ is used, the new Zone 1 ground would result in:

$$Z1G_{continuous} = 80\% \cdot \left|Z_{App,Continuous,k0segmented}\right| \angle(ZL_1)$$
$$= 6.06\angle 87.5° \ \Omega_{\text{Primary}}$$

With these two fault scenarios now calculated, the results are summarized in Table 1 below, along with the reach under both scenarios. To simplify these results for the purposes of this paper, only magnitude is compared, and phase angle is neglected.

Table 1. Zone 1 Example Summary and Calculated Reach

|Zone 1 Ground| Setting	Reach with Z_{app} & Segmented Static	Reach with Z_{app} & Continuous Static
8.08	80%	107%

6.06	60%	80%

B. Pilot Distance Protection

Historically, the ground protection required to see faults at the remote terminal has been set based on faults on the transmission system with the line impedance parameters using segmented static conductors. The zero-sequence compensation in this scenario also uses these parameters. This results in a smaller zero sequence current (and conversely a larger apparent line impedance) seen by the transmission-line relays. This is not an issue for any overreaching impedance elements, as the smaller zero sequence current ensures the apparent impedance seen by the line relays reaches adequately beyond the remote terminal. Conversely, if the overreaching ground impedance element is set using continuous static conductors, then there is a possibility the relays may not see as far past the remote terminal as expected, in the event the flashover does not occur at the segmentation points. Table 2 below demonstrates the effect on reach due to selecting settings for segmented or continuous static conductors.

i. Example Calculation of Zone 2 Impedance Based Reach

Considering the same line as in the Zone 1 Reach example along with the same fault taken, the Zone 2 setting using line parameters with segmented static conductors would be as follows:

$$Z2G_{Segmented} = 150\% \cdot \left|Z_{App,Segmented}\right| \angle(ZL_1)$$
$$= 15.17\angle 87.5° \ \ \Omega_{\text{Primary}}$$

(The Dominion Energy standard is to achieve Zone 2 reach of 150%.)

Conversely, the Zone 2 setting if the line parameters are using continuous static conductors would be:

$$Z2G_{Continous} = 150\% \cdot \left|Z_{App,Continuous,k0Segmented}\right| \angle(ZL_1)$$
$$= 11.37\angle 87.5 \ \Omega_{\text{Primary}}$$

Table 2 provides a summary of the Zone 2 results and calculated reach under each scenario.

Table 2. Zone 2 Example Summary and Calculated Reach

|Zone 2 Ground| Setting	**Reach with Z_{app} & Segmented Static**	**Reach with Z_{app} & Continuous Static**
15.17	150%	200%
11.37	112%	150%

C. Pilot Ground Overcurrent Detection

Compared to pilot distance protection, a similar philosophy can be used for overcurrent protection used in communication assisted schemes like Permissive Overreaching Transfer Trip or Directional Comparison Blocking. However, in a communication assisted scheme using pilot ground overcurrent, the flashover of the static conductors improves reach since $3I_0$ would be greater when compared to the fault current seen by the transmission line relays if no segmentation points flash over. Like the pilot ground distance reach, the relay reach will fall well below the minimum requirement if the pilot ground overcurrent is set using the $3I_0$ due to the continuous static conductors.

i. Example Calculation of Pilot Overcurrent Reach

Pilot ground overcurrent reach is determined using the same line parameters with segmented static conductors. Using the same line and the same faults as in the previous examples, a reach of 2.0 for a remote L-G fault will be used to determine the setting for the pilot ground overcurrent settings:

$$67G2_{Segmented} = \frac{|3I_{0,Segmented}|}{2.0} = \frac{4240}{2.0}\ \mathrm{A_{Primary}}$$
$$67G2_{Segmented} = 2120\ \mathrm{A_{Primary}}$$

Now using the fault data seen by the line relay due to the change with the continuous static conductors, the pilot ground overcurrent setting is recalculated using the new $3I_0$ values:

$$67G2_{Continuous} = \frac{|3I_{0,Continous}|}{2.0} = \frac{5122}{2.0}\ \mathrm{A_{Primary}}$$
$$67G2_{Continuous} = 2561\ \mathrm{A_{Primary}}$$

The reach of pilot ground overcurrent setting is calculated by dividing the measured current by the pickup setting (4):

$$Reach = \frac{I_{Fault}}{I_{PickUp}} \tag{4}$$

A summary of these results, along with the calculated reach in each scenario, can be found in Table 3.

Table 3. Pilot Overcurrent Example Summary and Calculated Reach

|67G2| Setting	Reach with Segmented Static	Reach with & Continuous Static
2120	2	2.42
2561	1.66	2

D. Backup Ground Inverse Time Overcurrent Protection

Segmented static conductors play a role in setting backup ground (BUG) inverse-time overcurrent protection, as well. Traditionally, overcurrent pickup values are determined by meeting the minimum reach for L-G faults at the remote bus. Since the minimum reach is concerned with the lowest possible flow of fault current, a segmented static model should be used. With the impedance being larger than the continuous static alternative, a smaller magnitude of current is present. Furthermore, any flashover at the segmentation points causes the zero-sequence impedance to decrease (and the zero-sequence current to rise), and reach is inherently improved. However, when checking coordination of the BUG with adjacent relays, a bolted close-in fault at the adjacent relay, while using the continuous static model of the studied line, is preferred. This is because the reduced impedance will result in larger fault currents, thereby causing the inverse-time overcurrent curves to operate faster.

i. Example BUG Coordination Study

Consider the power system topology and fault location given in Figure 11.

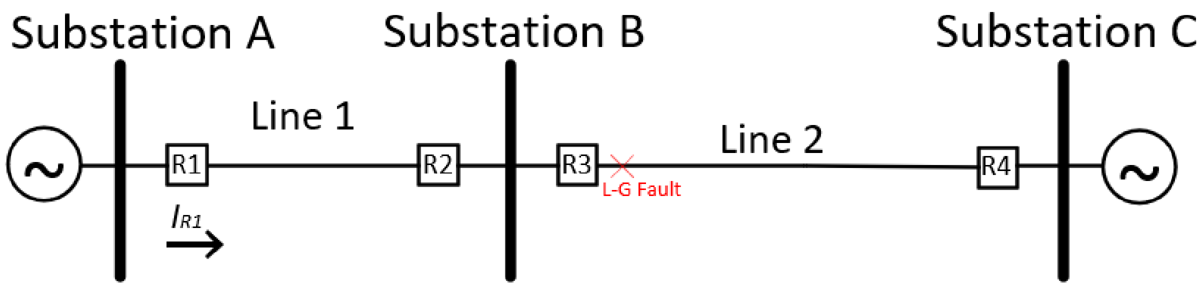

Figure 11. Power System Topology for BUG Example

When a close-in bolted L-G fault occurs at Substation B, Relay 3 will pick up on its backup ground inverse-time overcurrent element. Assuming the pickup value has adequate reach, the BUG at Relay 1 will also detect the fault.

Consider the following parameters for Line 1 along with the fault current seen by Relay 1 (I_{R1}):

$$ZL_{0,Segmented} = 59.98\angle 81.9°$$
$$I_{R1,Segmented} = 4422 \text{ A}_{\text{Primary}}$$

$$ZL_{0,Continuous} = 46.37\angle 70.7°$$
$$I_{R1,Continuous} = 5214 \text{ A}_{\text{Primary}}$$

Based on these fault currents and Equation (4) to achieve a reach of 2.0, the inverse-time overcurrent pickup derived yields these different results:

$$51G_{Pickup,Segmented} = \frac{I_{R1,Segmented}}{2.0} = \frac{4422}{2.0} = 2211 \text{ A}_{\text{Primary}}$$

$$51G_{Pickup,Continuous} = \frac{I_{R1,Continuous}}{2.0} = \frac{5214}{2.0} = 2607 \text{ A}_{\text{Primary}}$$

With the inverse time pickup now calculated, the reach under each scenario is compared in Table 4 below.

Table 4. BUG Overcurrent Example Calculated Pickup Reach

51G Pickup Setting	Reach under Segmented Static Conditions	Reach under Continuous Static Condition
2211	2.0	2.4
2607	1.66	2.0

Clearly, a significant difference in fault current is measured depending on the model used. Since the actual line may not flash over at every single segmentation point, the most conservative approach is to use the segmented model for reach determination. This way, a smaller fault current is ensured. Conversely, a more severe fault current is desired when checking coordination. In this scenario it is preferable for Relay 3 to clear the fault first, followed by Relay 1 sometime later. Due to the inherent nature of inverse-time overcurrent curves, a larger current will cause the relay to operate faster. Consider the overcurrent curves shown in Figs. 12a and 12b. This data was obtained by simulating the fault illustrated in Figure 11, using a segmented static model for Line 1 (Fig. 12a) and a continuous model for Line 1 (Fig. 12b). The blue curve is associated with Relay 1, while the red one belongs to Relay 3.

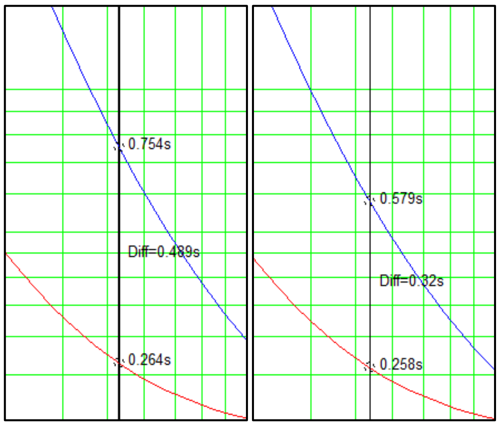

Figure 12a. **Figure 12b.**

Figure 12. BUG Operating Times using Segmented Model (Left) and Continuous Model (Right)

Figure 12a demonstrates the operating times for Relays 1 and 3 when a segmented static model is used for Line 1. Relay 3 trips first in 0.264 seconds, then Relay 1 trips 0.489 seconds later. On the other hand, Figure 12b shows the operating times when the static conductors become continuous on Line 1. Relay 3's speed does not change very much, but Relay 1 now trips significantly faster. This is because Relay 1 is measuring more fault current. Also, the time separation between curves decreases when the continuous model is used. Dominion Energy strives to maintain at least 0.2 seconds of separation between time overcurrent curves to ensure proper coordination, per IEEE [6]. The measured time difference will be more conservative using the continuous model since it represents a worst-case situation. Therefore, continuous static models are utilized when checking BUG coordination.

VI. CONCLUSION

In systems where segmented static conductors are used and the BIL is low enough to allow for fault-current-induced flashovers, the changes in zero sequence impedance can cause the high-speed underreaching protection to inadvertently trip for a fault well past the remote terminal. When breaks in the shield wire occur for other reasons, such as crossing underneath another line, the issue of not reaching enough is introduced if the gap is not accounted for in the line's impedance. This study shows the line impedance with continuous static conductors should be used when setting the high-speed underreaching protection. Conversely, the pilot overreaching element needs to be sensitive enough to ensure the protection reaches beyond the remote terminal. This selectivity in the overreaching protection will also ensure adequate reach for any blocking elements. For these reasons, line impedance with segmented static conductors should be used when setting the overreaching and blocking protection.

VII. BIBLIOGRAPHY

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