Considerations When Using Charging Current Compensation in Line Current Differential Applications

Jordan Bell, Ariana Hargrave, Greg Smelich, and Brian Smyth
Schweitzer Engineering Laboratories, Inc.

Presented at the
46th Annual Western Protective Relay Conference
Spokane, Washington
October 22–24, 2019

Previous revised edition released March 2019

Originally presented at the
72nd Annual Conference for Protective Relay Engineers, March 2019

Considerations When Using Charging Current Compensation in Line Current Differential Applications

Jordan Bell, Ariana Hargrave, Greg Smelich, and Brian Smyth, *Schweitzer Engineering Laboratories, Inc.*

***Abstract*—Every high-voltage transmission line draws a capacitive charging current. The longer the line, the more charging current is drawn. If line current differential relays do not compensate for this charging current, they will interpret it as differential current that can cause the protection scheme to operate. Charging current compensation methods are available in line current differential relays to achieve secure transmission line protection.**

This paper shows how to calculate charging current and determine whether compensation is recommended for a protected transmission line. Additionally, this paper investigates two misoperations caused by misapplications of charging current compensation.

I. Introduction

Charging current exists on all transmission lines and cables due to the inherent capacitive reactance of the conductors. Because charging current enters the line from each end and escapes through the distributed capacitance, it appears as standing differential current to a line current differential (87L) scheme protecting the line. If there is a significant amount of charging current, it is necessary to modify the scheme to prevent a misoperation. For this reason, charging current compensation is often implemented in 87L applications.

One common method of mitigating the effects of charging current on a protection scheme is to set the pickup level high enough that the protection scheme does not operate for this condition. However, doing so reduces scheme sensitivity to faults on the line. Some microprocessor-based relays subtract a fixed amount of charging current based on settings provided by the engineer, but this value may not be accurate for changing system conditions or switching configurations. Other relays can dynamically compensate for charging current. This is done by first calculating the charging current using measured instantaneous line voltage values along with settings provided by the engineer. The calculated charging current is then removed from the differential calculations [1].

The misapplication of charging current compensation can lead to relay misoperation. To ensure the proper application of charging current compensation, settings engineers should have basic knowledge of charging current theory and related calculations. They also need to be familiar with the compensation method used by the 87L scheme and have a clear understanding of the associated protective relay settings. This paper reviews charging current theory, calculations, and compensation methods. It also provides guidelines to help engineers determine if charging current compensation is recommended to improve the security of 87L schemes.

II. Theory of Charging Current

A. What Is Charging Current?

The amount of charging current on a line depends on the voltage level, line length, spacing between conductors, and distance from the line to the ground. Charging current exists mainly in the positive sequence and has a typical magnitude of 1 to 2 A/mi primary for overhead lines.

The charging current examples in this paper use two types of line models, shown in Fig. 1. Each model can be used to illustrate overhead transmission lines or underground cables. (Additional models exist but are not described in this particular paper.) In both models, the line consists of series resistance (R), series reactance (X), and shunt capacitance (C_{LINE}). Fig. 1a shows the T-model, in which the entire shunt capacitance is assumed to be lumped in the middle of the line and half of the line resistance and reactance is on either side. Fig. 1b shows the π-model, in which the series impedance of the line is in the center and the shunt capacitance is divided into two equal parts on either end of the line.

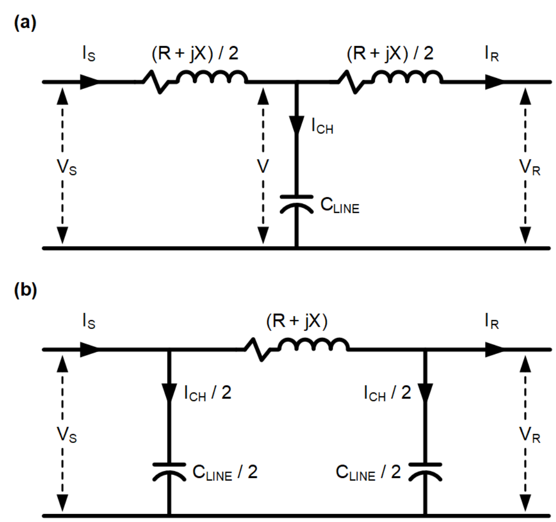

Fig. 1. (a) T-Model of a Transmission Line; (b) π-Model of a Transmission Line

In both models, the current that flows through the shunt capacitance of the line is called charging current. Although this current flows through all transmission lines and cables during normal system operation (as well as during system transients), it is commonly ignored for short-circuit studies.

Most protection analysis uses a simple series impedance to model transmission lines. This simplification is accurate enough for most transmission line models, but not for underground cables or long overhead lines. In these cases, engineers must include shunt capacitance in the short-circuit model and consider the effect of the charging current on the 87L scheme. The amount of charging current depends largely on line length, voltage level, and whether the conductor is overhead or underground.

Engineers should note that a long, ultra-high-voltage line cannot be modeled adequately with a π-model and requires the use of a distributed parameter model instead. Even then, the charging current compensation might not be sufficient. The engineer might still need to desensitize the relay to get acceptable results.

In the steady state, the charging currents in each phase are relatively equal because of conductor symmetry. This means that the charging currents exist mainly in the positive sequence, and that the negative- and zero-sequence components are negligible. However, this changes during transient conditions like line energization and internal and external faults. In addition, charging current can create challenges, such as when a line is energized from only one end. In this situation, the voltage at the receiving end of a long transmission line or underground cable is higher than the voltage at the sending end because of the capacitive charging current flowing on the line. The same effect occurs on lightly loaded lines. This effect, known as the Ferranti effect, is prominent for long lines and underground cables because the conductors on these lines have higher capacitance.

B. Calculating Charging Current

To address charging current in an 87L scheme, a settings engineer first needs to know how much charging current exists for the protected line. Charging current is present during steady-state and transient conditions. When developing settings, often the settings engineer is concerned only with the steady-state charging current and obtains the value either from simulation software or manual calculations based on system parameters.

Manual calculations involve several common equation versions. A settings engineer chooses to use one version over another based on factors such as parameter availability or the acceptability of certain assumptions. This section of the paper reviews these common equations used by engineers to calculate steady-state charging current and to determine whether to apply compensation or not. It also makes the connection between calculations performed by a protective relay and settings entered by the protection engineer.

An approximation of charging current is made by assuming there is no load flow ($I_R = 0$) and no voltage drop across the line impedance ($V_S = V = V_R$) in a T-model transmission line (see Fig. 1a). With those assumptions, the charging current (I_{CH}) flowing through the line capacitance (C_{LINE}) is calculated as shown in (1).

$$I_{CH} = C_{LINE} \bullet \frac{dV}{dt} \tag{1}$$

For a three-phase line, I_{CH} and V are replaced with matrices to include all three phases. The self-capacitance and mutual capacitance of each conductor must also be considered, so (1) becomes (2).

$$\begin{bmatrix} I_{ACH} \\ I_{BCH} \\ I_{CCH} \end{bmatrix} = \begin{bmatrix} C_S & C_M & C_M \\ C_M & C_S & C_M \\ C_M & C_M & C_S \end{bmatrix} \bullet \frac{d}{dt} \begin{bmatrix} V_{A\_AVE} \\ V_{B\_AVE} \\ V_{C\_AVE} \end{bmatrix} \tag{2}$$

where:

I_{ACH}, I_{BCH}, and I_{CCH} are the phase charging currents.

C_S is the self-capacitance of each conductor.

C_M is the mutual capacitance between each phase in negative value.

V_{A_AVE}, V_{B_AVE}, and V_{C_AVE} are the root-mean-square (rms) voltages.

If the line is fully transposed, the C_S values are all equal and positive, and the C_M terms are all equal and negative. The assumption of line transposition is discussed later in this section.

Reference [2] describes the calculation of shunt capacitance for a three-phase conductor or cable, and it provides the equation used for calculating charging current when the self-capacitance and mutual capacitance of the line are known, shown in (3). The Section IX appendix shows the derivation of (3) from (2).

$$\begin{bmatrix} I_{ACH} \\ I_{BCH} \\ I_{CCH} \end{bmatrix} = j\omega \begin{bmatrix} C_{AA} & -C_{AB} & -C_{AC} \\ -C_{BA} & C_{BB} & -C_{BC} \\ -C_{CA} & -C_{CB} & C_{CC} \end{bmatrix} \bullet \begin{bmatrix} V_{A\_AVE} \\ V_{B\_AVE} \\ V_{C\_AVE} \end{bmatrix} \tag{3}$$

where:

$C_{AA} = C_{AG} + C_{AB} + C_{AC}$.

$C_{BB} = C_{BG} + C_{AB} + C_{BC}$.

$C_{CC} = C_{CG} + C_{BC} + C_{AC}$.

C_{AB}, C_{AC}, and C_{BC} are the mutual capacitances in positive value.

C_{BA}, C_{CA}, and C_{CB} are equal to C_{AB}, C_{AC}, and C_{BC}, respectively.

$\omega = 2 \bullet \pi \bullet$ frequency.

Equation (4) is then used to calculate the zero-, positive-, and negative-sequence components of the charging current [3].

$$\begin{bmatrix} I_{0CH} \\ I_{1CH} \\ I_{2CH} \end{bmatrix} = \begin{bmatrix} A^{-1} \end{bmatrix} \bullet \begin{bmatrix} I_{ACH} \\ I_{BCH} \\ I_{CCH} \end{bmatrix} \tag{4}$$

where:

A is the transformation matrix used to convert phase quantities to symmetrical components, defined by

$$A = \begin{bmatrix} 1 & 1 & 1 \\ 1 & a^2 & a \\ 1 & a & a^2 \end{bmatrix}$$

with $a = 1\angle 120°$.

This method provides a close approximation of charging current, but the calculations are more complex than other common methods and require the self-capacitance and mutual capacitance values, which can be difficult to obtain.

In many cases, a settings engineer only needs to know the magnitude of the positive-sequence charging current, I_{1CH}, which is assumed to be equal to any of the phase charging currents (I_{ACH}, I_{BCH}, or I_{CCH}). This assumption is only valid if the line is fully transposed and the voltage source is balanced. If this is the case, and I_{1CH} is the only quantity of interest, the engineer can use an alternative method to simplify the previous calculations.

The capacitance and voltage matrices in (3) are first transformed into sequence components using (5) and (6), respectively. Then, the zero-sequence charging current, I_{0CH}; the positive-sequence charging current, I_{1CH}; and the negative-sequence charging current, I_{2CH}, are calculated using (7).

$$\begin{bmatrix} C_{00} & -C_{01} & -C_{02} \\ -C_{10} & C_{11} & -C_{12} \\ -C_{20} & -C_{21} & C_{22} \end{bmatrix} = \left[A^{-1}\right] \bullet \begin{bmatrix} C_{AA} & -C_{AB} & -C_{AC} \\ -C_{BA} & C_{BB} & -C_{BC} \\ -C_{CA} & -C_{CB} & C_{CC} \end{bmatrix} \bullet [A] \quad (5)$$

$$\begin{bmatrix} V_{0\_AVE} \\ V_{1\_AVE} \\ V_{2\_AVE} \end{bmatrix} = \left[A^{-1}\right] \bullet \begin{bmatrix} V_{A\_AVE} \\ V_{B\_AVE} \\ V_{C\_AVE} \end{bmatrix} \quad (6)$$

$$\begin{bmatrix} I_{0CH} \\ I_{1CH} \\ I_{2CH} \end{bmatrix} = j\omega \begin{bmatrix} C_{00} & -C_{01} & -C_{02} \\ -C_{10} & C_{11} & -C_{12} \\ -C_{20} & -C_{21} & C_{22} \end{bmatrix} \bullet \begin{bmatrix} V_{0\_AVE} \\ V_{1\_AVE} \\ V_{2\_AVE} \end{bmatrix} \quad (7)$$

where:

C_{00}, C_{11}, and C_{22} are the zero-, positive-, and negative-sequence capacitances, respectively.

C_{01}, C_{02}, and C_{12} are the mutual capacitances between the sequence networks in positive value.

C_{10}, C_{20}, and C_{21} are equal to C_{01}, C_{02}, and C_{12}, respectively.

For simplicity, this paper refers to the zero-, positive-, and negative-sequence capacitances in (5) and (7) as C_0, C_1, and C_2, respectively.

Like the method using (3) and (4), the method using (7) provides a close approximation of charging current but requires more complicated matrix operations. However, simplification of (7) is straightforward when the line is fully transposed (or assumed to be). The effect of line transposition on the capacitance matrix is described in [2]. When a transmission line is fully transposed, the self-capacitances and mutual capacitances in (3) are equal. This results in non-zero values in the main diagonal of the sequence component matrix in (5) and zero values in the off-diagonal positions. That is, the sequence networks are decoupled and there is no mutual capacitance between them.

The assumption of line transposition is convenient for calculating charging current because it allows (7) to be simplified into (8), (9), and (10) for I_{0CH}, I_{1CH}, and I_{2CH}.

$$I_{0CH} = j\omega C_0 V_{0\_AVE} \quad (8)$$

$$I_{1CH} = j\omega C_1 V_{1\_AVE} \quad (9)$$

$$I_{2CH} = j\omega C_2 V_{2\_AVE} \quad (10)$$

If the system is assumed to be balanced, then (9) can be further simplified, as shown in (11). This is one common form used to calculate I_{1CH} if the assumptions of a transposed line and a balanced line-to-line voltage source (V_{PH-PH}) are acceptable.

$$I_{1CH} = j\omega C_1 \frac{V_{PH-PH}}{\sqrt{3}} \quad (11)$$

The positive-sequence shunt capacitance of an example overhead 525 kV transmission line is 0.0188 μF/mi primary (0.0071 mS/mi at 60 Hz), a typical capacitance value for overhead transmission lines. Using this value for C_1 in (11), Table I lists approximate charging current values for various overhead transmission line voltage levels.

TABLE I
TYPICAL CHARGING CURRENT VALUES

Voltage Level	Charging Current Value (A/mi)
765 kV	3.10–3.20
525 kV	2.05–2.20
345 kV	1.35–1.45
230 kV	0.90–0.98
115 kV	0.45–0.50
69 kV	0.25–0.30

Some protective relays calculate charging current using the settings for positive- and zero-sequence susceptance, while other relays use shunt reactance in ohms. For simplicity, this paper uses susceptance in calculations.

Because the shunt capacitance branches in Fig. 1 are assumed to be purely reactive, there is no conductance. The admittance is therefore composed of only the susceptance, B_{LINE}, resulting in the relationship shown in (12).

$$B_{LINE} = \omega \bullet C_{LINE} \quad (12)$$

Generally, protective relay settings require values in secondary milliSiemens for zero- and positive-sequence susceptance. However, zero- and positive-sequence capacitance values are usually provided or requested in primary Farads. Unit conversion is handled using (13), which relates the zero-sequence capacitance in primary Farads to the zero-sequence susceptance in secondary milliSiemens, and (14), which does the same for the positive-sequence values.

$$C_0 = \frac{B_0 \bullet CTR}{\omega \bullet 1{,}000 \bullet PTR} \quad (13)$$

$$C_1 = \frac{B_1 \bullet CTR}{\omega \bullet 1{,}000 \bullet PTR} \quad (14)$$

where:

B_0 and B_1 are the zero- and positive-sequence susceptance values in secondary milliSiemens (relay settings units).

CTR is the current transformer (CT) ratio.

PTR is the potential transformer (PT) ratio.

Substituting (14) into (11) results in another common equation for calculating the primary positive-sequence charging current, I_{1CH}, shown in (15).

$$I_{1CH} = j \bullet \frac{B_1}{1{,}000} \bullet \frac{V_{PH-PH}}{\sqrt{3}} \bullet \frac{CTR}{PTR} \tag{15}$$

Although (11) and (15) are commonly used by protection engineers, these equations lack the accuracy required for a protective relay algorithm designed to compensate for line charging current. To bridge the connection between the zero- and positive-sequence settings, B_0 and B_1, and the equations used by a protective relay for compensation, an engineer must first define the zero- and positive-sequence capacitance in terms of the self-capacitance and mutual capacitance. These equations, (16) and (17), are derived by expanding (5).

$$C_0 = \frac{C_{AA} + C_{BB} + C_{CC} - 2C_{AB} - 2C_{BC} - 2C_{CA}}{3} = C_S + 2C_M \tag{16}$$

$$C_1 = \frac{C_{AA} + C_{BB} + C_{CC} + C_{AB} + C_{BC} + C_{CA}}{3} = C_S - C_M \tag{17}$$

where:

C_S is the self-capacitance and is equal to $(C_{AA} + C_{BB} + C_{CC}) / 3$.

C_M is the mutual capacitance in negative value [2] and is equal to $-(C_{AB} + C_{BC} + C_{CA}) / 3$.

Substituting (13) into (16) and (14) into (17) and then solving the set of equations gives (18) and (19) for calculating the self-capacitance and mutual capacitance (in primary Farads) in terms of the zero- and positive-sequence susceptance values (in secondary milliSiemens).

$$C_S = \frac{(B_0 + 2 \bullet B_1)}{3{,}000 \bullet \omega} \bullet \frac{CTR}{PTR} \tag{18}$$

$$C_M = \frac{(B_0 - B_1)}{3{,}000 \bullet \omega} \bullet \frac{CTR}{PTR} \tag{19}$$

With the self-capacitance and mutual capacitance known and the measured voltage available, the protective relay uses an equation similar to (3) to calculate the charging current for each phase. The actual calculations performed by this protective relay use self- and mutual-susceptance values, i.e., (18) and (19) multiplied by ω, and the calculations are done in secondary quantities. However, primary values, self-capacitance values, and mutual capacitance values are used in this section to make the connection between the algorithm used by the relay and the equations commonly used by settings engineers to calculate charging current.

III. Methods of Charging Current Compensation

It is generally acceptable to ignore the effects of line charging current for overhead lines shorter than 50 mi when developing relay settings. However, with increased operating voltage and lines longer than 50 mi, the larger values of charging current must be accounted for. The compensation methods discussed here relate primarily to 87L protection schemes. For more information on line charging current and how it affects other relay algorithms, such as distance and directional elements, see [1].

A. Accounting for Charging Current With Settings

A common approach to mitigating the charging current is to program the protection settings accordingly. This is generally done by setting the pickup of the overcurrent and line current differential elements at 120 percent of the calculated charging current. Because the charging current for each phase consists primarily of positive-sequence current (i.e., zero- and negative-sequence charging currents are negligible), it is generally not necessary to adjust the pickup settings for protection schemes that operate on negative- or zero-sequence current.

This approach has two disadvantages. First, increasing the pickups of the protection elements limits the sensitivity of the scheme whenever the charging current is significant. Second, engineers can only neglect modifying the zero- and negative-sequence pickups when the zero- and negative-sequence voltages (V_0 and V_2) are negligible. During a fault, V_0 and V_2 can be significant, resulting in high-magnitude zero- and negative-sequence charging currents that are not negligible.

B. Current-Based Compensation (Steady State Removal)

Another compensation approach for 87L schemes involves subtracting the steady-state charging current from the measured current to remove it from the standing differential current. Some relays allow the engineer to enter a fixed value for line charging current that is always subtracted from the differential current. This approach works well in steady-state operation, but during fault transients or voltage changes due to loading, the amount of charging current can change. In these situations, subtracting a fixed value can introduce more error than not compensating at all.

In an enhanced version of this approach, the relay creates a memorized value prior to a fault condition by averaging the differential current magnitude over a few cycles. Once a disturbance is detected, this average differential current magnitude is frozen and subtracted from the instantaneously measured value to improve sensitivity. This accounts for variations in line loading. However, this method is challenged during line energization because there is no current prior to the energization. In addition, the charging current is highest at the moment the breaker is closed, meaning that a higher charging current than usual is subtracted from the measured differential current, further desensitizing the element until the system stabilizes. To secure protection during this condition, some relays automatically apply additional timers or increased pickup settings during the energization of a line when charging current inrush takes place.

C. Voltage-Based Compensation

In general, phasor-based current compensation methods are challenged during transient conditions. Current flowing through the capacitance and reactance of a transmission line responds in the time domain based on the change in voltage over time (dV/dt). Modern microprocessor relays dynamically compensate for line charging current by calculating the charging current and removing it from the differential calculation in real time. A microprocessor relay uses line voltage instantaneous values and line susceptance values (both positive- and zero-sequence) to calculate the real-time charging current. This technique allows for a more sensitive 87L scheme (because there is no need to raise the pickup to account for the charging current) and for correct compensation during changing system voltage conditions. Reference [1] describes this technique in detail.

The relays in the 87L scheme compensate for line charging current by calculating the total charging current on each phase and subtracting it from the differential current. Each relay in the scheme that measures voltage calculates the total charging current of the line with the local voltage measurement and engineer-provided line susceptance settings. The relays use the zero- and positive-sequence susceptance values of the line to determine the self- and mutual-susceptance values, as described in Section II, Subsection B.

Next, each relay subtracts a portion of the total charging current from the measured local phase current. The measured local phase current is the sum of all currents entering the local terminal and consists of either a single breaker measurement or the sum of two breaker measurements (in the case of a breaker-and-a-half or ring-bus configuration). Assuming a lumped parameter model, the portion of the total charging current subtracted from the measured local currents is proportional to the number of compensating terminals. For example, when two relays compensate for the charging current, each relay subtracts half of the total charging current from its measured local current, as shown in (20) and (21).

$$I_L = I_{MEASURED\_L} - 0.5 \bullet C_{LINE} \bullet \frac{dV_L}{dt} \tag{20}$$

$$I_R = I_{MEASURED\_R} - 0.5 \bullet C_{LINE} \bullet \frac{dV_R}{dt} \tag{21}$$

If three relays are compensating for the charging current, each subtracts a third of the total charging current. Each relay performs this subtraction before using its local current in the 87L function and before transmitting its current measurements to the remote relays.

In actual transmission lines, it is unlikely that the total charging current is split equally between the terminals. However, compensating in each relay as though this current is evenly split produces the same result in the differential calculation as having unequal contributions from each end. When the relays calculate the differential current, they each arrive at the value resulting from (22) with the entire charging current removed.

$$\begin{aligned} I_{DIF} &= I_L + I_R \\ I_{DIF} &= I_{MEASURED\_L} + I_{MEASURED\_R} - C_{LINE} \bullet \frac{d}{dt}\left(\frac{V_L + V_R}{2}\right) \end{aligned} \tag{22}$$

The net outcome is that the 87L system effectively uses the average line voltage to calculate the charging current but does so without any need to send and receive voltage signals between terminals (as shown in Fig. 2).

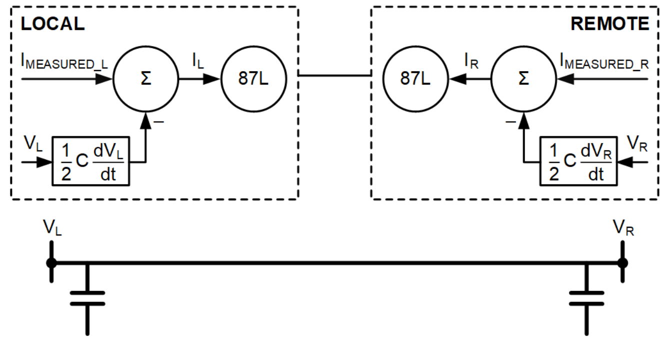

Fig. 2. Subtracting Line Charging Current From the 87L Scheme

The number of relays that compensate for the charging current at any given time can change based on the number of relays that measure accurate voltage. When the voltage measured by an individual relay does not accurately represent the voltage on the line, that relay suspends compensation. Examples of this scenario include a breaker opening on a relay with bus-side PTs or a loss-of-potential condition.

A given relay asserts a bit when it is actively compensating, and it shares this bit with all other relays in the scheme, so every relay knows how many relays are compensating at a given time. When a given relay suspends compensation, the other relays in the scheme continue to compensate, each subtracting a new portion of the total charging current based on the number of actively participating relays. The more relays participating, the better the quality of the compensation calculation. Other bits are available to show when compensation is using all the expected terminals and when compensation quality is degraded because not all of the expected terminals are participating.

For more information on the design of a voltage-based compensation algorithm, see [4].

IV. When to Apply Compensation and Sensitivity

There is no standard or rule for enabling charging current compensation methods. Understanding the calculations and applying them helps the engineer evaluate the impact of the charging current in their application and determine whether compensation is required to maintain sensitivity and security. This section provides some general guidelines.

As noted in Section III, charging current is typically ignored for overhead lines less than 50 mi long. It is also ignored for system voltages less than 115 kV.

A further consideration is whether the line is underground. A short underground cable can have as much charging current as that of a long overhead line due to the capacitance developed between the cable and the conduit and the proximity to the ground. Reference [2] calculates the charging current in three different lines and shows that the charging current in a

5 mi underground cable is similar to the charging current of a 100 mi overhead line with the same voltage level.

To make an informed decision on the impact of line charging current, the engineer must calculate the positive-sequence charging current for the line using (11) or (15). Equation (11) requires the positive-sequence shunt capacitance, which is calculated using (23). This can also be calculated using a commercially available short-circuit study computer program.

$$C_1 = \frac{2\pi\varepsilon}{\ln \dfrac{d_M}{r_{EQ}}} \qquad (23)$$

where:

$d_M = \sqrt[3]{d_{AB} \bullet d_{AC} \bullet d_{BC}}$ and is the geometric mean distance among the three phases.

$r_{EQ} = \sqrt[n]{n \bullet r \bullet R^{n-1}}$ and is the equivalent radius for an *n*-subconductor bundle. R is the radius of that bundle.

r = the radius of the subconductor.

ε = the permittivity of the dielectric medium between the conductors. For overhead transmission lines, the permittivity of air is approximately equal to $\varepsilon = \varepsilon_0 = 8.854 \bullet 10^{-12}\,F$ per meter.

In ultra-high-voltage lines, such as 765 kV lines, the charging current can be over 1,000 A primary or even larger than the load current in some cases. In those cases, subtracting the standing differential current from the charging current is not advisable. A proper compensation method, such as the voltage-based compensation method, provides greater security than a nontransient or standing differential current subtraction method.

The scenarios in Table II and Table III include sample calculations for determining whether charging current compensation is necessary for an 87L scheme. Line length, system voltage, and positive-sequence susceptance are provided for each scenario. The pickup setting for the 87L scheme in these scenarios is 1.0 per unit (pu). To calculate the charging current in per unit of the current differential pickup setting, I_{1CH} is divided by the CTBASE. The CTBASE is the highest primary value of all the local and remote CTs.

TABLE II
COMPENSATION EVALUATION SCENARIO 1

Characteristic	Value
Line length	50 mi
System voltage	500 kV
B_1	9.8 µS/mi primary
CTBASE	2,000 A
I_{CH}	$\frac{500\text{ kV}}{\sqrt{3}} \bullet 50\text{ mi} \bullet 0.0098\text{ mS/mi} = 141\text{ A primary}$
I_{CHPU}	$\frac{141\text{ A}}{2{,}000\text{ A}} = 0.071\text{ pu}^*$

*The charging current is approximately 7 percent of the 87L pickup setting; therefore, compensation is likely not required in this scenario.

TABLE III
COMPENSATION EVALUATION SCENARIO 2

Characteristic	Value
Line length	250 mi
System voltage	500 kV
B_1	9.8 µS/mi primary
CTBASE	2,000 A
I_{CH}	$\frac{500\text{ kV}}{\sqrt{3}} \bullet 250\text{ mi} \bullet 0.0098\text{ mS/mi} = 707\text{ A primary}$
I_{CHPU}	$\frac{707\text{ A}}{2{,}000\text{ A}} = 0.354\text{ pu}^*$

*The charging current is greater than 35 percent of the 87L pickup setting; therefore, one of the previously mentioned compensation methods should be considered.

V. Applying Charging Current Compensation With Shunt Reactors

In a line application, a reactor located in the differential protection zone can be either fixed or switchable. The reactor current measurement can be included or excluded in the relay differential protection zone as follows:

- *Included*—reactor CTs are not summed into the relay; therefore, the relays measure the combined current of the reactor and the shunt capacitance.
- *Excluded*—reactor CTs are summed into the relay; therefore, the reactor current measurement is summed with the line protection CTs and removed from the differential protection zone.

If line reactors are installed, the charging current will be significant enough to require compensation. If a transmission line requires compensation, then the 87L protection scheme will require it as well. This compensation is handled by the line reactors if the reactors are included in the zone of protection. If the reactors are excluded from the zone of protection, then the 87L algorithm in the relay must handle charging current compensation.

It is recommended that engineers exclude line-side reactors from differential protection zones by wiring reactor CTs such that the reactor current is subtracted from the line current. Then, an engineer can set compensation based on full line susceptance. This is the most appropriate method, but it might not be feasible for all applications. Section VI, Subsections D and E discuss how to handle charging current compensation for scenarios where reactors are included in the differential zone and scenarios where reactors are excluded from it.

VI. Misoperation of 87L Scheme, Case 1: Charging Current Compensation Enabled When Line Reactors Present

A. Background

This section studies a misoperation of an 87L scheme with charging current compensation enabled on a 525 kV transmission line. (Reference [5] was used to aid the analysis.) The line is protected by an 87L scheme and two permissive overreaching transfer trip (POTT) schemes using distance and directional overcurrent. There are three shunt reactors on the line. Preliminary investigation showed that the operation was inconsistent with a fault on the line because this was the only relay that operated on the transmission line (other distance-based and overcurrent-based relays did not operate). In addition, system operations reported no fault on that line or the adjacent lines.

Fig. 3 is the Station A 87L relay event record that shows the current and voltage at the time of misoperation.

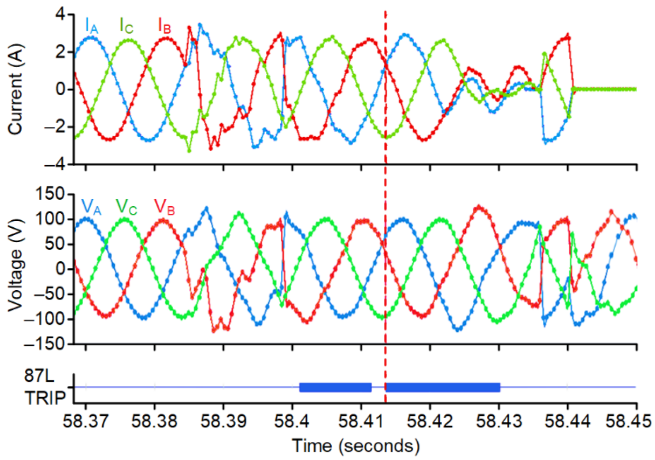

Fig. 3. Current and Voltage Event Record From Station A 87L Relay

The top graph shows the measured line currents (secondary amperes), the middle graph shows the voltages (secondary volts), and the bottom graph shows the digital element (87L trip operation). While there are some distortions in the voltage and current waveforms, this event does not resemble one where an internal fault occurred on the transmission line and caused the relay to operate. Instead, this event record indicates some sort of switching operation internal or external to the line. Because this relay is an 87L relay, the differential current magnitudes for each phase were recorded. Fig. 4 shows that event record.

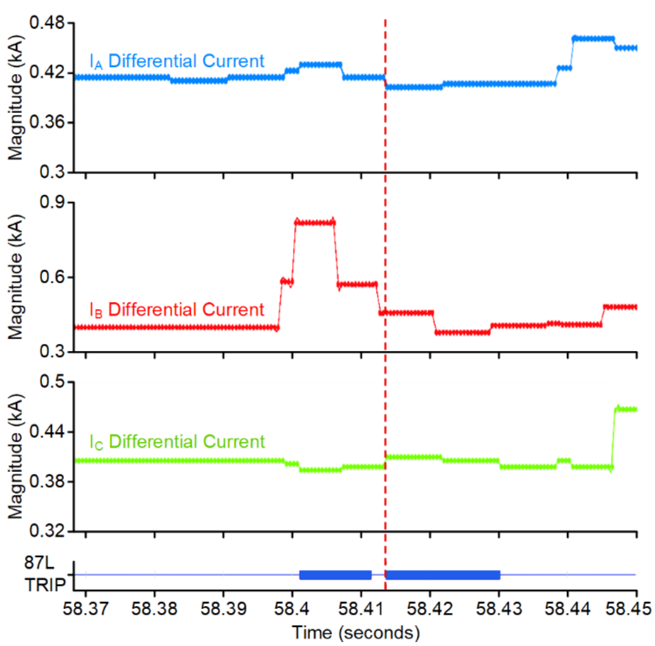

Fig. 4. Differential Current Event Record From Station A 87L Relay

The top graph shows the A-phase differential current, the middle graph shows the B-phase differential current, and the bottom graph shows the C-phase differential current. The A-phase and C-phase stay constant in magnitude; however, the B-phase shows a large magnitude increase that coincides with the differential trip. The event record also shows that the differential element 87L asserted, indicating that the relay performed a B-phase current differential trip.

With no visible fault taking place, it was initially unclear what caused the relay to operate. However, a clue was provided by the magnitudes of the differential current on all three phases prior to the 87L operation. When the differential current magnitude in the steady state was reviewed, there was a standing differential current with magnitude of approximately 400 A. This was unexpected because the charging current compensation was enabled and set correctly for the line susceptance. The current in the steady state was expected to be approximately 0 A, not 400 A.

The transmission line is 215 mi in length. Using (11), the charging current calculated for this line is approximately 462 A. To compensate for this standing differential current, the microprocessor-based relays used a voltage-based charging current compensation algorithm. When enabled, this algorithm subtracted the line charging current and compensated the differential current appropriately so that the standing differential current measured by the relay was approximately zero. To verify if the relay was set to use this function, the related relay settings were inspected. These settings are shown in Table IV.

TABLE IV
CHARGING CURRENT COMPENSATION SETTINGS

Parameter	Value
Number of terminals	2
Positive-sequence capacitive reactance (XC_1)	0.662 kΩ
Zero-sequence capacitive reactance (XC_0)	1.234 kΩ

The charging current compensation was enabled using the positive- and zero-sequence shunt capacitive reactance of the line. If the charging current compensation function was enabled, why was there a large standing differential current?

Long transmission lines draw a large amount of capacitive charging current; therefore, to counteract this capacitive current, shunt compensation is typically employed in the form of line reactors. Might these line reactors have been the source of the standing differential current?

Both stations in the system (A and B) showed line reactors included in the differential protection zone. There was one reactor located at Station A and two at Station B. All three reactors were rated at 125 MVAR. This corresponds to a shunt compensation of 137 A at 525 kV for each reactor. Therefore, all three reactors combined provided approximately 411 A of reactive shunt compensation, leaving 51 A of capacitive charging current that was drawn from the system.

The reactors were providing the line with steady-state reactive compensation. Because the reactors were included in the differential zone, charging current compensation should not have been enabled in the relay. The necessary compensation was already being performed by the reactors.

Section V recommends that engineers exclude reactors from the differential protection zone and use the time-domain charging current compensation in 87L relays. In this case where the reactors were included, additional margin in the minimum sensitivity should be included to account for the transient differential current, which results from the different dV/dt response of the lumped reactive compensation and the distributed charging current during a disturbance.

B. Line Parameters

Table V shows the shunt values and the positive-sequence impedance for this 215 mi transmission line in primary values.

TABLE V
LINE SHUNT CAPACITANCE, SUSCEPTANCE, AND IMPEDANCE

Parameter	Value
Positive-sequence shunt capacitive reactance (XC_1)	0.662 kΩ
Positive-sequence shunt susceptance (B_1)	1.53 mS
Positive-sequence capacitance (C_1)	4.05 µF
Zero-sequence shunt capacitive reactance (XC_0)	1.234 kΩ
Zero-sequence shunt susceptance (B_0)	0.83 mS
Zero-sequence capacitance (C_0)	2.20 µF
Positive-sequence impedance (Z_1)	124∠88 Ω

With the charging current known, the voltage at the remote Station B terminal under no-load conditions can be calculated using (24) and a π-model with half of the susceptance at each end of the line.

$$\begin{aligned} V_{REMOTE} &= V_{LOCAL} - I_{CH} \bullet Z_{1_{LINE}} \\ &= 525\text{ kV } \angle 0° - 231\text{ A } \angle 90° \bullet 124\ \Omega\ \angle 88° \\ &= 554\text{ kV } \angle -0.2° \end{aligned} \tag{24}$$

This charging current under a no-load or lightly loaded condition created a significant overvoltage of 554 kV at Station B, given a system voltage of 525 kV when energized from Station A. This illustrates the Ferranti effect mentioned in Section II. A similar condition occurred at Station A when the line was energized from Station B. For this reason, three line reactors were installed: one at Station A and two at Station B.

Each line reactor was rated at 125 MVAR. The amount of inductive current compensation each one provided is calculated by taking the reactor rating and dividing by the system voltage, as shown in (25).

$$I_{REACTOR1} = \frac{S_{REACTOR1}}{\sqrt{3} \bullet 525\text{ kV}} = 137\text{ A} \tag{25}$$

C. Including a Line Reactor in the Differential Zone of Protection

Fig. 5 shows a distributed parameter model with the remote terminal open. The Station A reactor is installed on the transmission line and included in the differential protection zone.

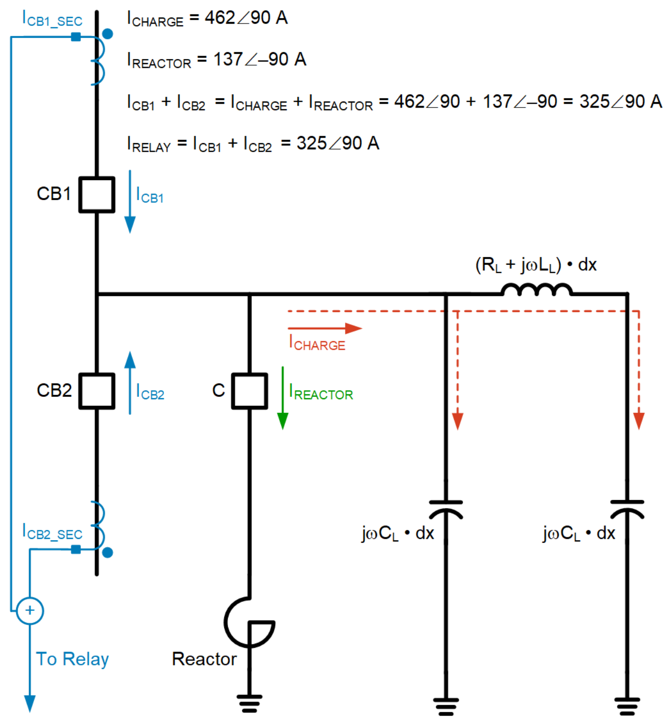

Fig. 5. Reactor Current Included in Differential Protection Zone

The reactor provides inductive reactive current compensation proportional to the reactor. Because each reactor compensates for 137 A, the Station A reactor reduces the charging current that the 87L relay measures from 462 to 325 A. If the reactor is switched out of service, it no longer provides reactive compensation and the 87L relay measures the full 462 A of capacitive charging current.

In this configuration, it is not straightforward to set the charging current compensation in an 87L relay because the current to compensate varies and the standing differential current changes accordingly. The 87L relay needs multiple settings groups with different shunt compensation settings to account for changing line configurations when the reactor is in service and when the reactor is out of service. It is also necessary to communicate the status of the line reactor to the relay to make the settings group change dynamically.

D. Excluding a Line Reactor From the Differential Zone of Protection

Fig. 6 shows a distributed parameter model that has the Station A reactor in service and the reactor current summed into the CT secondary circuits going to the relays. The current summation in the CT secondary is polarity-dependent. In a configuration such as this, care must be exercised to connect the CTs appropriately.

Whether the reactor is in service or out of service, the relay measures the same current. If the reactor is in service and providing reactive compensation, the current measured by the relay is given by (26).

$$I_{RELAY} = I_{CB1} + I_{CB2} - I_{REACTOR} \tag{26}$$

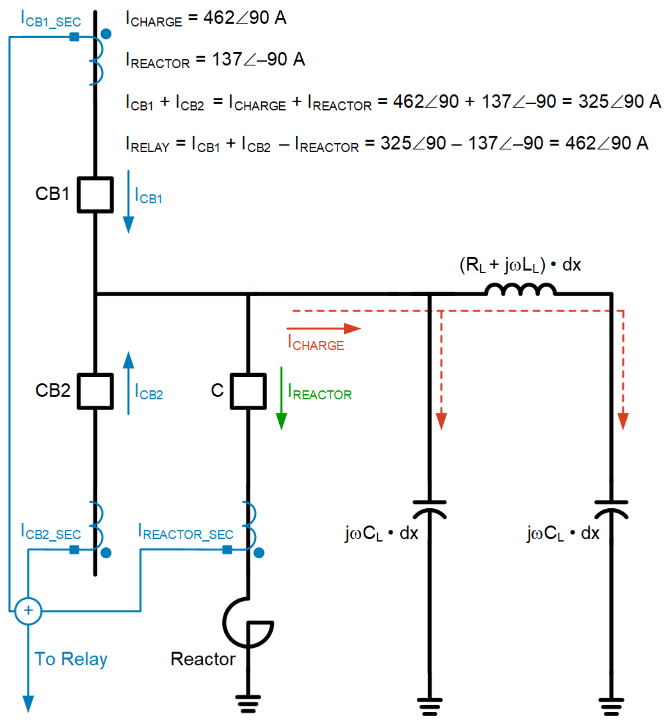

Fig. 6. Reactor Current Excluded From Differential Protection Zone

If the reactor is switched out, then current $I_{REACTOR}$ is zero and it redistributes to I_{CB1} and I_{CB2}, so the current that the relay measures remains unchanged. In this configuration, the charging current compensation in an 87L relay can be set and used reliably regardless of reactor status, so the status does not need to be communicated to the relay, and multiple settings based on that status are not necessary.

E. Settings Verification

A real-time digital simulator was used to test a model of the power system to verify the relay current differential measurements. This helped determine appropriate charging current compensation settings based on the inclusion of the line reactors in the differential zone of protection.

The line was open-ended; therefore, only current measurement was performed from Station A. In addition, charging current compensation was disabled to ensure measurement accuracy when the included reactors were switched in and out of service in different configurations. The results are shown in Table VI.

TABLE VI
CHARGING CURRENT MEASUREMENTS

Description	Current
All reactors in service	44 A
All reactors out of service	480 A
Station A reactor out of service; both Station B reactors in	185 A
Station A reactor out of service; one Station B reactor in	327 A
Station A reactor in service; both Station B reactors out	333 A
Station A reactor in service; one Station B reactor in	185 A

With all reactors in service, there was still some capacitive current drawn, meaning that the transmission line was not perfectly compensated by the reactors. The scenario with all line reactors out of service showed the total charging current of the transmission line. The scenarios with the reactors switched in and out of service showed the effect the reactors had on the capacitive charging current measured by the relay.

Engineers initiated and tested a configuration with the Station A reactor excluded and the two reactors at Station B included in the differential zone of protection. This reactor arrangement, based on a distributed parameter model, used charging current compensation with positive-sequence shunt capacitive reactance of 1.615 kΩ and zero-sequence shunt capacitive reactance of 2.977 kΩ.These correspond to positive- and zero-sequence susceptance values of 0.62 mS and 0.34 mS, respectively. These relay settings compensated the portion of the line not affected by the included reactors. All three line reactors were then switched in and out of service in various configurations, and the charging current measured by the 87L relays was observed. These observations are shown in Table VII.

TABLE VII
STANDING DIFFERENTIAL CURRENT FOR VARIOUS LINE REACTOR CONFIGURATIONS

Station A Reactor 1	Station B Reactor 2	Station B Reactor 3	Charging Current
Out	Out	Out	270 A
In	Out	Out	270 A
In	In	Out	125 A
Out	In	Out	125 A
In	In	In	40 A
Out	In	In	40 A

The smallest standing differential current measured occurred when both Station B line reactors were switched in service. The largest standing differential current measured occurred when both Station B line reactors were switched out of service. With charging current compensation enabled and the proper capacitive reactance settings applied, the worst-case standing differential current decreased from 480 A to 270 A. The 480 A with a primary CT base of 2,000 A corresponded to a pickup of 0.24 pu. The 270 A corresponded to a pickup of 0.135 pu. This difference allowed for a decrease in the 87L pickup if a higher sensitivity was required. The standing differential current was approximately 40 A with all three line reactors switched in service.

VII. MISOPERATION OF 87L SCHEME, CASE 2: INCORRECT CHARGING CURRENT COMPENSATION SETTINGS

A. Background

This section discusses a misoperation during the commissioning of an 87L scheme on a short (<50 mi), 220 kV transmission line running from Station S to Station R. There were no faults on the system. Engineers retrieved the metering information from the relay at Station S and the relay at Station R (this information is listed in Table VIII and Table IX). At each relay, the magnitudes of the phase currents were approximately equal and the phase angles were balanced, with expected phase rotations. Comparing the angles for a single phase (e.g., A-phase, B-phase, or C-phase) between the two relays showed that they were approximately 180 degrees out of phase, which was also expected. These characteristics confirmed proper wiring in each substation.

TABLE VIII
STATION S METERING

Channel	Current
I_A	$76\angle 35$ A
I_B	$78\angle -82$ A
I_C	$76\angle 155$ A

TABLE IX
STATION R METERING

Channel	Current
I_A	$60\angle -165$ A
I_B	$62\angle -74$ A
I_C	$57\angle -47$ A

Because the 87L scheme operated during commissioning, a differential metering command was issued to verify the calculated local and remote current values. Investigation revealed that the local and remote terminal values were in phase, indicating an internal fault. With correct metering values indicated for each relay, focus turned to the 87L calculation and corresponding settings. As mentioned previously, charging current compensation is applied only to the differential current and not the local currents. The differential metering values for Station S are shown in Table X. Similar values exist for Station R, but are not shown.

TABLE X
STATION S DIFFERENTIAL METERING

Channel	Current
I_A local	$1.78\angle 0$ pu
I_B local	$1.77\angle -120$ pu
I_C local	$1.77\angle 120$ pu
I_A remote	$1.74\angle 0$ pu
I_B remote	$1.73\angle 120$ pu
I_C remote	$1.75\angle 120$ pu
I_A differential	$3.52\angle 0$ pu
I_B differential	$3.50\angle -120$ pu
I_C differential	$3.52\angle 120$ pu

B. *Line Parameters and Settings*

The settings found in the relays are listed in Table XI.

TABLE XI
SETTINGS PARAMETERS

Description	Value
CTR	800
PTR	2,000
Location of PT	Line side
Positive-sequence line susceptance (B_1)	94 mS
Zero-sequence line susceptance (B_0)	55 mS

It is important to pay attention to the units for these settings. Many computational programs provide these susceptance values, but they can be in different units than the values in the relay settings. If a value is entered with incorrect units, it can cause the relay to calculate charging current incorrectly and lead to a misoperation.

The values for the zero- and positive-sequence line susceptance settings were obtained from a short-circuit program. This program outputs the values of B_0 and B_1 in primary microSiemens. However, the relay required secondary values in milliSiemens. When performing the conversion, the settings engineer incorrectly multiplied the primary values by CTR / PTR (instead of PTR / CTR) and did not change the units from microSiemens to milliSiemens. This led to the entry of incorrect settings for the zero- and positive-sequence susceptance into the 87L relays. For example, the positive-sequence susceptance setting was entered as 94 mS instead of the correct value of 0.591 mS. The incorrect settings resulted in a charging current compensation that was 160 times larger than the expected value.

This specific relay used a voltage-based charging current compensation method. Assuming a secondary measured voltage of 63.5 V, the relay measured a charging current of 6.026 A secondary, or 4.8 kA primary. This amount of charging current looked like a purely internal fault to the relay, and it caused the relay to measure the differential current incorrectly, leading to the misoperation during commissioning.

Correcting the short-circuit program units to milliSiemens results in a primary charging current of approximately 30 A, or 0.0375 A secondary. If a CTBASE of 4,000 and an 87L pickup of 1.0 pu are assumed (the actual values were not available at the time of publication), the resulting charging current in per unit is 30 A / 4,000 A = 0.0075 pu. Comparing the charging current in per unit to the 87L pickup setting shows that the charging current is less than one percent of the pickup setting (0.0075 / 87L pickup • 100% = 0.75%). Based on those values, charging current compensation was likely not required for this short, 220 kV line.

When this event was analyzed and the charging current impact evaluated, it was determined that compensation was not needed. However, if correct settings were applied to the relay, it would not have misoperated. This example shows why it is so important to verify the units of values provided by an outside program before entering them in as relay settings.

VIII. Conclusion

Charging current presents many challenges to protective relaying. However, modern microprocessor-based protective relays can correctly compensate for charging current and provide reliable protection.

Typically, charging current compensation is not required on short overhead lines less than 50 mi or for low voltage levels (less than 115 kV). As the voltage level increases, the requirement of short lines is not always consistent. A 765 kV transmission line can have substantial charging current that adversely affects the protection applied and needs to be compensated. Engineers must also consider the effect of underground cabling: even a short cable can exhibit as much charging current as a long ultra-high-voltage transmission line due to the close proximity between the cable and the conduit.

Applications with line reactors can compensate for charging current effectively if the reactor locations and relay connections are considered. Performing real-time digital simulator testing helps avoid misoperations because engineers gain understanding of the charging current under various conditions and can verify all relay settings before putting it into service. Programs used to generate line parameters and susceptance values can be useful, but careful attention to measurement units is critical. Engineers must verify that the units from these programs match the units that the relay settings require before implementing charging current compensation.

IX. Appendix: Derivation of Line Charging Current Under Balanced Conditions

This section shows the derivation of (3) from (2), beginning with an evaluation of the derivative term in (2). A simplified equation for charging current under balanced conditions results from applying the assumption of balanced voltages to (2).

A set of balanced voltages is defined in (27).

$$\begin{bmatrix} V_{A\_AVE} \\ V_{B\_AVE} \\ V_{C\_AVE} \end{bmatrix} = \begin{bmatrix} \left|V_{A\_AVE}\right| \cos\left(\omega t + 0°\right) \\ \left|V_{B\_AVE}\right| \cos\left(\omega t - 120°\right) \\ \left|V_{C\_AVE}\right| \cos\left(\omega t + 120°\right) \end{bmatrix} \tag{27}$$

The derivative of the voltages in (27) is shown in (28).

$$\frac{d}{dt}\begin{bmatrix} V_{A\_AVE} \\ V_{B\_AVE} \\ V_{C\_AVE} \end{bmatrix} = \begin{bmatrix} -\left|V_{A\_AVE}\right| \sin\left(\omega t + 0°\right) \bullet \omega \\ -\left|V_{B\_AVE}\right| \sin\left(\omega t - 120°\right) \bullet \omega \\ -\left|V_{C\_AVE}\right| \sin\left(\omega t + 120°\right) \bullet \omega \end{bmatrix} \tag{28}$$

A sine function is a cosine function shifted by –90 degrees, or sin(ωt + 0°) = cos(ωt–90°), so (28) can be written in terms of cosine functions, as shown in (29).

$$\frac{d}{dt}\begin{bmatrix} V_{A\_AVE} \\ V_{B\_AVE} \\ V_{C\_AVE} \end{bmatrix} = \begin{bmatrix} -\left|V_{A\_AVE}\right| \cos\left(\omega t - 90°\right) \bullet \omega \\ -\left|V_{B\_AVE}\right| \cos\left(\omega t - 210°\right) \bullet \omega \\ -\left|V_{C\_AVE}\right| \cos\left(\omega t + 30°\right) \bullet \omega \end{bmatrix} \tag{29}$$

Rewriting (29) with phasor notation and incorporating the fact that –cos(ωt – 90°) = cos(ωt + θ + 180°), (30) is obtained.

$$\frac{d}{dt}\begin{bmatrix} V_{A\_AVE} \\ V_{B\_AVE} \\ V_{C\_AVE} \end{bmatrix} = \begin{bmatrix} \omega\left|V_{A\_AVE}\right|\left(1\angle 90°\right) \\ \omega\left|V_{B\_AVE}\right|\left(1\angle -30°\right) \\ \omega\left|V_{C\_AVE}\right|\left(1\angle -150°\right) \end{bmatrix} \tag{30}$$

The (1∠90°) component is then factored out of each term on the right side of (30). Because (1∠90°) in polar notation is equal to 1j (or simply "j") in rectangular notation, the derivative term from (2) can be expressed as (31).

$$\frac{d}{dt}\begin{bmatrix} V_{A\_AVE} \\ V_{B\_AVE} \\ V_{C\_AVE} \end{bmatrix} = \begin{bmatrix} j\omega\left|V_{A\_AVE}\right| \\ j\omega\left|V_{B\_AVE}\right|\left(1\angle -120°\right) \\ j\omega\left|V_{C\_AVE}\right|\left(1\angle +120°\right) \end{bmatrix} = j\omega\begin{bmatrix} V_{A\_AVE} \\ V_{B\_AVE} \\ V_{C\_AVE} \end{bmatrix} \tag{31}$$

The capacitance matrix in (2) represents the self-capacitance and mutual capacitance of the line, C_S and C_M, respectively, where C_M is in negative value [2]. An alternative expression for this matrix uses the self-capacitances (C_{AA}, C_{BB}, and C_{CC}) and the mutual capacitances (C_{AB}, C_{AC}, and C_{BC}) in positive value. Using the latter form and substituting (31) into (2), we obtain (3), which is shown again here for completeness.

$$\begin{bmatrix} I_{ACH} \\ I_{BCH} \\ I_{CCH} \end{bmatrix} = j\omega\begin{bmatrix} C_{AA} & -C_{AB} & -C_{AC} \\ -C_{BA} & C_{BB} & -C_{BC} \\ -C_{CA} & -C_{CB} & C_{CC} \end{bmatrix} \bullet \begin{bmatrix} V_{A\_AVE} \\ V_{B\_AVE} \\ V_{C\_AVE} \end{bmatrix}$$

X. References

[1] A. Hargrave and G. Smelich, "Setting and Testing Line Charging Current Compensation in the SEL-411L Relay," SEL Application Guide (AG2018-02), 2018. Available: selinc.com.

[2] Y. Xue, D. Finney, and B. Le, "Charging Current in Long Lines and High-Voltage Cables – Protection Application Considerations," proceedings of the 39th Annual Western Protective Relay Conference, Spokane, WA, October 2012.

[3] S. Chase, S. Sawai, and A. Kathe, "Analyzing Faulted Transmission Lines: Phase Components as an Alternative to Symmetrical Components," proceedings of the 71st Annual Conference for Protective Relay Engineers, College Station, Texas, March 2018.

[4] H. Miller, J. Burger, N. Fischer, and B. Kasztenny, "Modern Line Current Differential Protection Solutions," proceedings of the 63rd Annual Conference for Protective Relay Engineers, College Station, TX, March 2010.

[5] E. Nashawati, N. Fischer, B. Le, and D. Taylor, "Impacts of Shunt Reactors on Transmission Line Protection," proceedings of the 38th Annual Western Protective Relay Conference, Spokane, WA, October 2011.

XI. Biographies

Jordan Bell received his BSEE from Washington State University in 2006. He joined Schweitzer Engineering Laboratories, Inc. (SEL) in 2008 as a protection engineer in the SEL Engineering Services, Inc., group. He is currently a senior engineer and supervisor in that group, working on event report analysis, relay settings and relay coordination, fault studies, and model power system testing with a real-time digital simulator. He is a registered professional engineer in the state of Washington and a member of IEEE.

Ariana Hargrave earned her BSEE, magna cum laude, from St. Mary's University in San Antonio, Texas, in 2007. She graduated with a master of engineering degree in electrical engineering from Texas A&M University in 2009, specializing in power systems. Ariana joined Schweitzer Engineering Laboratories, Inc. in 2009 and works as a protection application engineer in Fair Oaks Ranch, Texas. She is an IEEE member and a registered professional engineer in the state of Texas.

Greg Smelich earned a B.S. in mathematical science and an M.S. in electrical engineering from Montana Tech of the University of Montana, in 2008 and 2011, respectively. Greg then began his career at Schweitzer Engineering Laboratories, Inc. (SEL) as a protection application engineer, where he helped customers apply SEL products through training and technical support, presented product demonstrations, worked on application guides and technical papers, and participated in industry conferences and seminars. In 2016, Greg made the transition to the SEL R&D group as a product engineer, where he now helps guide product development, training, and technical support related to time-domain technology. He has been a certified SEL University instructor since 2011 and an IEEE member since 2010.

Brian Smyth received a BSEE and MSEE from Montana Tech at the University of Montana in 2006 and 2008, respectively. He joined Montana Tech as a visiting professor in 2008 and taught classes in electrical circuits, electric machinery, instrumentation and controls, and power system analysis. He joined Schweitzer Engineering Laboratories, Inc. (SEL) in 2009 and is currently a senior product engineer in the transmission group. Brian joined Montana Tech of the University of Montana in 2014 as an adjunct professor, where he teaches a course in power system protection in addition to working for SEL. He received the Montana Tech Alumni Recognition Award in 2015 in recognition of his professional accomplishments and the IEEE Engineer of the Year award from Montana's Society of Engineers in 2017. He is an IEEE member and a registered professional engineer in the state of Washington.

20190821 • TP6895-01